Appendix N. Mississippi Canyon 252 No. 1 (Macondo) Basis of Design Review

Overview

This appendix reviews BP casing design requirements and verifies that Macondo well casing was designed in accordance with the BP requirements. The attached report summarizes a review of the casing design for the Macondo well using actual well conditions.

The report found that the casings for the Macondo well met or exceeded the load case recommended by the BP Tubular Design Manual, BPA-D-003 with certain limited exceptions that did not affect the integrity of the design.

BP policy sets conservative design factors as the starting point for well control load cases, but other loads may be considered following external review, as was done correctly for the Macondo well. The attached report found that the BP Macondo well team obtained all appropriate dispensations for the identified deviations from BPA-D-003 for the casing design.

Conclusions

The investigation team concluded that the production casing met all required design conditions and that it was highly unlikely that a casing failure mode contributed to the loss of well control.

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Mississippi Canyon 252 No. 1 (Macondo)

Basis of Design Review

Report No. 10-812-9509-01			
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Revision	1.0		July 27, 2010

1 Executive Summary

1.1 Conclusions

1. The majority of loads to which the Mississippi Canyon 252 No. 1 well tubulars were subjected during design equal or exceed those recommended by the BP *Tubular Design Manual*. Exceptions to the manual recommendations (enumerated below) are discussed in the next section of this summary.

   (a) The 36 in. conductor satisfies all standard load cases and associated design factors as enumerated in the BP *Tubular Design Manual* with one minor exception. The internal pressure profile for the Lost Circulation load case is parallel to, but slightly higher (40 psi) than that recommended by the BP *Tubular Design Manual*, indicating the StressCheck load case to which the 36 in. casing was designed to be slightly less severe than that recommended by BP design practice. This discrepancy should not have serious impact on the design (see Section 1.2).

   (b) The 28 in. conductor satisfies all standard load cases and associated design factors as enumerated in the BP *Tubular Design Manual* with one minor exception. The internal pressure profile for the Lost Circulation load case is parallel to, but slightly higher (40 psi) than that recommended by the BP *Tubular Design Manual*, indicating the StressCheck load case to which the 28 in. casing was designed to be slightly less severe than that recommended by BP design practice. This discrepancy should not have serious impact on the design (see Section 1.2).

   (c) The 22 in. surface casing satisfies all standard load cases and associated design factors as enumerated in the BP *Tubular Design Manual* with one exception. The upper section of the design cannot satisfy the Fracture @Shoe w/ Gas Gradient Above well control load case, but does satisfy the Gas Kick Profile load case with BP input parameters. This discrepancy is addressed in a deviation request which replaces the Fracture @Shoe w/ Gas Gradient Above load case with Gas Kick Profile.

   (d) The 16 in. intermediate liner satisfies all standard load cases and associated design factors as enumerated in the BP *Tubular Design Manual* with three exceptions:

      i. The internal pressure profile for the Pressure Test load case is absent from the design of this string. This appears to be an inadvertent load case omission. See Section 4.2 for further details.

      ii. The internal pressure profile for the Lost Circulation load case is parallel to, but slightly higher (291 psi) than that recommended by the BP *Tubular Design Manual* indicating the StressCheck load case to which the 16 in. casing was designed to be slightly less severe than that recommended by BP design practice. This discrepancy should not have serious impact on the design (see Section 1.2).

iii. The design cannot satisfy the Fracture @Shoe w/ Gas Gradient Above well control load case, and does not satisfy the Gas Kick Profile load case with BP input parameters (1.06 as compared to a minimum acceptable value of 1.10). The triaxial design factor is acceptable for all load cases at all depths.

(e) The 13-5/8 in. intermediate liner satisfies all standard load cases and associated design factors as enumerated in the BP *Tubular Design Manual* with one exception. The internal pressure profile for Lost Circulation is parallel to, but higher (748 psi) than that recommended by the BP *Tubular Design Manual* indicating the StressCheck load case to which the 13-5/8 in. liner was designed to be less severe than that recommended by BP design practice (see Section 1.2).

(f) The 11-7/8 in. intermediate liner satisfies all standard load cases and associated design factors as enumerated in the BP *Tubular Design Manual* with one exception. The internal pressure profile for Lost Circulation is parallel to, but slightly higher (322 psi) than that recommended by the BP *Tubular Design Manual* indicating the StressCheck load case to which the 11-7/8 in. liner was designed to be slightly less severe than that recommended by BP design practice (see Section 1.2).

(g) The 9-7/8 in. intermediate liner satisfies all standard load cases and associated design factors as enumerated in the BP *Tubular Design Manual* with one exception. The internal pressure profile for the Pressure Test load case is absent from the design of this string. This appears to be an inadvertent load case omission. See Section 4.2 for further details.

(h) The 9-7/8 in. $\times$ 7 in. production casing satisfies all standard load cases and associated design factors as enumerated in the BP *Tubular Design Manual* with one exception. The internal pressure profile for the Pressure Test load case is absent from the design of this string. This appears to be an inadvertent load case omission. See Section 4.2 for further details.

2. The BP design practice for surface and intermediate casing and liners aligns with standard industry practice, deviations being of a nature that are either open to designer preference or not crucial to tubular integrity.

3. The BP design practice for production casing and liners aligns with standard industry practice, deviations being of a nature that are either open to designer preference or not crucial to tubular integrity.

4. Regarding a check of the Mississippi Canyon 252 No. 1 casing using as-built variables:

   - As was the case with the original design discussed above, the 22 in. casing will not meet the loads associated with Fracture @Shoe w/ Gas Gradient Above, but will meet the loads associated with Gas Kick Profile with BP input parameters.
   - As was the case with the original design discussed above, the 16 in. casing will meet neither the loads associated with Fracture @Shoe w/ Gas Gradient Above nor Gas Kick Profile. The shortfall for the latter case is, however, not large (1.04 vs. required 1.10 for final Burst design factor; 1.23 vs. 1.25 for final Triaxial design factor.)

1.2 Deviations

The previous section summarizes deviations[1] from the BP *Tubular Design Manual* without regard to how those deviations were processed. The BP *Drilling and Well Operations Practice* [5] details a process by which deviations from the *Casing and Tubing Design Group Practice* may be obtained, given review and approval by the appropriate Deviation Authority. For the conclusions reached above, Table 1 summarizes the documentation of exceptions to the BP *Casing and Tubing Design Group Practice* [4].

Actually, the deviations for well control load listed in Table 1 provide clarity to the design process but, in this case, are not strictly necessary[2]. According to the BP *Casing and Tubing Design Group Practice* [4], “All casing and liners shall be designed to withstand reasonably foreseeable well control burst loadings. The starting point for well control burst loading shall be gas to surface from casing shoe, or lower open hole fracture pressure. Casing designs using lesser well control loadings not appearing in the *BP Tubular Design Manual* as acceptable alternatives shall be subject to review as per Well Category 2 in Table 1,” where Category 2 wells in Table 1 of [4] require a review level of “SPU plus review by a party external to the SPU”. In the case of the well control design validation for Mississippi Canyon 252 No. 1 the external party review was performed by S. C. Morey of EPT Drilling. Therefore, this external review by EPT satisfied the requirements of the subject ETP [4].

Of the deviations from standard BP design practice listed in Section 1.1, the remaining issues are the missing test pressure values (see Section 4.2 for a more detailed discussion) and discrepancies in the pore pressure used in calculating lost circulation (16 in., 13-5/8 in. and 11-7/8 in. strings). Regarding the latter, Figure 1 indicates that the levels of discrepancy noted in Section 1.1 will not affect the collapse design of the subject strings[3].

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[1] Until recently exceptions to normal design practice were termed “dispensations”. The use of “deviation” reflects current BP terminology.

[2] The following interpretation is based on an interview with M. L. Payne, BP Casing and Tubing Design SETA.

[3] Typically, the collapse load due to lost circulation is highest at the height to which the mud interface drops. For

Table 1. Mississippi Canyon 252 No. 1—Deviation Documentation

OD (in)	Deviation Sought	Document/Comments
36	None	Exception is very small.
28	None	Exception is very small.
22	Well control design load[a]	"22 Burst dispensation 6-20-2009.docm".
18	N/A	
16	Well control design load[a]	"16 Burst dispensation 6-20-2009.docm".
	Lost circulation design load[b]	See discussion of Figure 1 below.
13-5/8	Lost circulation design load[b]	See discussion of Figure 1 below.
11-7/8	Lost circulation design load[b]	See discussion of Figure 1 below.
9-7/8	N/A	
9-7/8 × 7	Fluid below packer (collapse)	"9 875 Collapse Dispensation 6-20-2009.docm", change datum and direction of calculation of internal pressure from atmospheric/down to abandonment/up[c].

[a]Replace Fracture@Shoe w/ Gas Gradient Above with Gas Kick Profile of 100 bbl kick volume, 2 ppg kick intensity, no fracture at casing shoe.

[b]Internal collapse pressure is higher than expected.

[c]This deviation is, according to the BP *Tubular Design Manual*, not necessary.

2 Introduction

This report summarizes a review of the tubular design for Mississippi Canyon 252 No. 1 (Macondo) to ascertain the character of that design as compared to both BP's internal *Tubular Design Manual* [3] and available industry practice. Both loads and resistance to those loads are verified, as are the character of the loads with respect to known industry practice. The base software used in the

these three strings, those depths are, respectively 852 ft, 1,208 ft and 798 ft. All these depths are significantly above the tops of the strings in question, resulting in the low collapse differential pressures plotted in Figure 1.

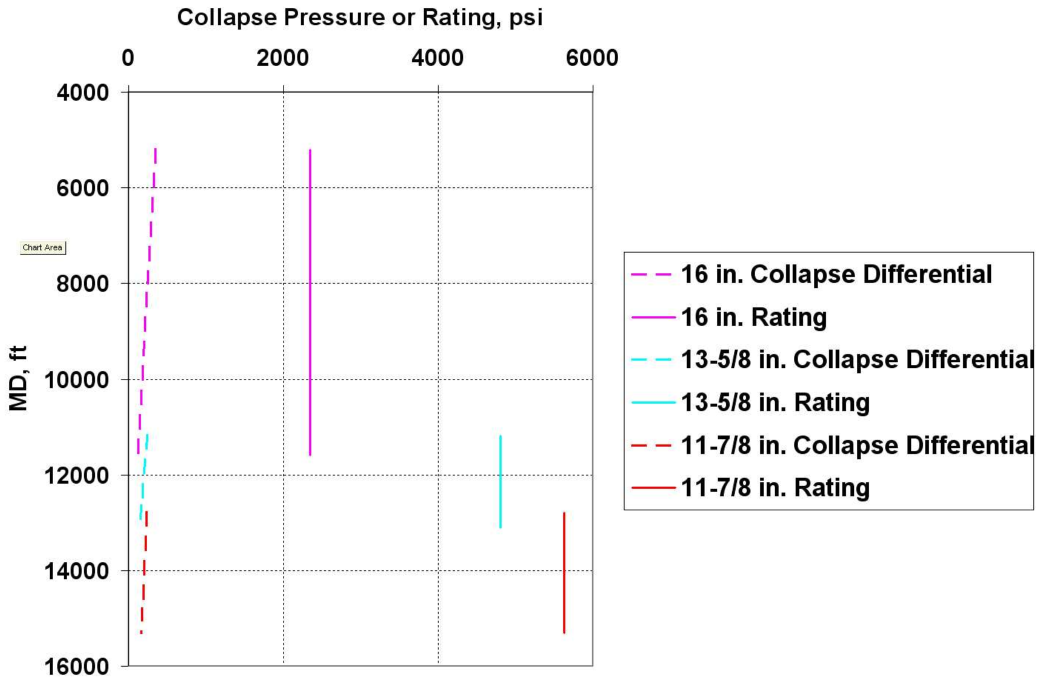

Figure 1. Lost Circulation Differential Collapse Pressures vs. Casing Collapse Ratings

review is a StressCheck file[4] entitled "Macondo (MC252#1) scm Mar 10.sck" with its accompanying document, "Evaluation of Casing Design Basis for Macondo Prospect, Mississippi Canyon Block 252, OCS-G-32306 Well No.1," Revision 4, Steve Morey, 22 March 2010. Changes to the design leading to Revision 4 are summarized in the report.

3 BP Standard Design Loads

Tables 2 through 4 have been extracted from the version of the BP *Tubular Design Manual* appropriate to the time of the design [3] and contain the standard BP assumptions for, respectively, conductor casing, surface and intermediate casing and production casing. The tables are summaries of material covered in more detail in later sections of the manual. In Tables 2 through 4 the headings are as follows:

- Service Life Load–Operational load applied to the casing;

[4]The file was processed using StressCheck Version 2003.16 Build 1061.

- Design Factors:
  - T = tension design factor;
  - B = burst design factor;
  - C = collapse design factor;
  - V = triaxial design factor;
- Additional Load Considerations–Additional analyses specific to the casing and load condition which must be considered;
- DLS–dogleg severity;
- Internal Pressure–pressure profile inside the casing string of interest;
- External Pressure–pressure profile in the annulus outside the casing string of interest;
- Temperature Profile[5]
  - S = Static gradient;
  - CMT = Cemented temperature;
  - CT = Circulating temperature while drilling;
  - PT = Production temperature.

Other important facts regarding the tables are as follows:

- The load cases appearing in Tables 2 through 4 have also been stored in the standard BP template from which each StressCheck design begins. If a user designates a casing string as intermediate casing, then the StressCheck template will automatically select the load cases from Table 3 appropriate to surface and intermediate casing.
- The entire BP *Tubular Design Manual* has the character of a recommended practice. Load cases and design principles are recommended practices for BP engineers and may be replaced or amended if the circumstances dictate[6]. All BP engineers, however, are taught to begin their analysis with the load cases of Tables 2 through 4 and as embodied in the BP StressCheck template.

[5]Thermal stresses are computed using the difference between the final temperature profile as listed in the table and an initial temperature profile assumed to exist at the time the cement solidifies sufficiently to inhibit axial movement of the casing. The initial temperature profile is almost always chosen to be the undisturbed, geostatic temperature.

[6]For example, the Above/Below Packer load case will not be used to design a production casing string that has no associated packer.

Table 2. Conductor Casing Design Loads

Load Case	Service Life Load Condition	Additional Load Considerations	Internal Pressure	External Pressure	Temp. Profile
Conductor Installation	Running conductor	• Bending due to DLS • Possible axial load due to lost circulation during running	SW/MW run in	SW/MW run in	S
	Cementing job–conventional	• Bending due to DLS • Axial load from bumping plug	MW or displacing fluid	MW, spacer, cement column from TOC	
	Cement job–stab in	• Bending due to DLS	MW	MW, spacer, cement column from TOC + bridging during operation[b]	
Burst loads after installation	Drilling–pressure test (if applicable)	• Bending due to DLS • Additional axial loads created by pressure test as calculated based on Poisson's effect (ballooning)	Pressure + fluid density during test	Pore pressure/SW gradient	
Collapse loads after installation	Drilling–lost circulation	• Tension analysis • Bending due to DLS	For offshore/onshore wells with sufficient source of water, the lowest internal gradient will be SW or FW, or evacuation or partial evacuation of casing due to mud column falling when drilling into an LC zone; mud column to fall until the hydrostatic pressure balances the LC zone, or complete evacuation if air or foam drilling.	MW used to set casing	

MW–drilling fluid density, SW–sea water

[b] Caution, packing of the annulus can result in high collapse loads.

Table 5 summarizes the minimum recommended design factors for BP casing and tubing designs that would be applied to the above load cases.

4 Application to Mississippi Canyon 252 No. 1

The casing diameters and pertinent axial locations (top, bottom, top of cement) are summarized in Table 6. The 7 in. production casing is actually a 9-7/8 in. $\times$ 7 in. tapered casing string, with crossover at 14,500 ft MD. The "Mud" column refers to the drilling fluid density in the hole at the time the tubular was run.

Table 3. Surface, Intermediate and Drilling Casing Design Loads

Load Case	Service Life Load Condition	Additional Load Considerations	Internal Pressure	External Pressure	Temp. Profile
During Installation	Running casing	• Bending due to DLS • Possible axial load due to lost circulation during running	MW run in	MW run in	S
	Cementing–conventional as cemented Base Case	• Bending due to DLS	Displacing fluid	MW/SW (as applicable), spacer, cement column from TOC	CMT
	Cementing–stab in job	• Bending due to DLS	MW	MW, spacer, cement column from TOC + bridging during operation[b]	
	Bumping cement plugs	• Bending due to DLS • Axial load due to pressure acting across area of casing ID	Displacing fluid + pressure used to bump plug	MW, spacer, cement column from TOC	
Burst loads after installation	Drilling–pressure test	• Bending due to DLS • Additional axial loads created by pressure test as calculated based on Poisson's effect (ballooning) • Casing wear, as required	Pressure + fluid density during test	Mix fluid above TOC; mix fluid below TOC to previous shoe if TOC above shoe, pore pressure in open hole assuming cement provides axial pressure isolation	S
	Drilling–max drilling MW if not cemented to surface	• Same as Drilling–pressure test • Helical buckling	Maximum MW to drill DSOH	Same as Drilling–pressure test	CT
	Drilling–well control, no hydrocarbon expected on basis of much data	Same as Drilling–pressure test	Seawater gradient from shoe fracture pressure	Same as Drilling–pressure test	
	Well control, possible hydrocarbon	• Same as Drilling–pressure test • Helical buckling	Gas gradient from shoe fracture pressure	Same as Drilling–pressure test	
Collapse loads after installation	Drilling–lost circulation	• Tension Analysis • Biaxial effect on collapse resistance due to axial stress	For offshore/onshore wells with sufficient source of water, the lowest internal gradient will be SW or FW, or evacuation or partial evacuation of casing due to mud column falling when drilling into an LC zone; mud column to fall until the hydrostatic pressure balances the LC zone, or complete evacuation if air or foam drilling.	MW used to set casing	S

MW–drilling fluid density, SW–sea water

[b] Caution, packing of the annulus can result in high collapse loads.

Table 4. Production Casing and Liner Design Loads

Load Case	Service Life Load Condition	Additional Load Considerations	Internal Pressure	External Pressure	Temp. Profile
During Installation	Running casing	• Bending due to DLS • Possible axial load due to lost circulation during running	MW run in	MW run in	S
	Cementing	• Bending due to DLS	Displacing fluid	MW, spacer, cement column from TOC	C
	Bumping cement plugs	• Bending due to DLS • Axial load due to pressure acting across area of casing ID	Displacing fluid + pressure used to bump plug	MW, spacer, cement column from TOC	
Exploration and Development	Pressure test	• Bending due to DLS • Additional axial loads created by Poisson's effect (ballooning) • Helical buckling	Pressure + fluid density during test	Mix fluid above TOC; mix fluid below TOC to previous shoe if TOC above shoe, pore pressure in open hole assuming cement provides axial pressure isolation	S
Development Burst Loads after Installation	Miscellaneous completion operations	• Same as Pressure test • Pressure and temperature loads for acid stimulation, fracture, water injection, *etc.* • Helical buckling	Pressure for production loads and fluid density	Same as Pressure test	S & P
	Tubing leak (also applicable to intermediate casing if used as production)	• Same as Pressure test	Tubing surface pressure (based on dry methane unless otherwise justified) + completion fluid	Same as Pressure test	
Exploration Burst Loads after Installation	DST pressure load	• Same as Pressure test	Surface pressure for downhole tool/gun operation and MW	Same as Pressure test	
	Gas or hydrocarbon to surface, DST string leak	• Same as Pressure test	Gas or hydrocarbon to surface from expected target pressure; for DST string leak, tubing surface pressure + MW	Same as Pressure test	S
Collapse Loads after Installation	Production collapse	• Tension analysis • Biaxial effect on collapse resistance due to axial stress	Annulus above packer: • Lowest completion fluid to balance depleted reservoir • For gas lift operations casing will be completely evacuated to max depth • Other completions and operations Annulus below packer: • Gas gradient (.1 psi/ft) or full evacuation for gas wells • Gas lift operation • Other operations	During 1st year MW used to set casing. After 1st year pore pressure in cemented section and MW above cement.	

MW–drilling fluid density, SW–sea water

Notes:

- In cases where a significant section is to be drilled below the production casing well control considerations should be designed for.
- In cases where a significant number of rotating hours are anticipated in drilling below the production casing shoe, the effects of casing wear should be considered.

Table 5. BP Minimum Casing and Tubing Design Factors

	Casing		Tubing (Test)		Tubing Service)	
Mode	Pipe	Coupling	Pipe	Coupling	Pipe	Coupling
Tension	1.4	1.4	1.1	1.1	1.33	1.33
Burst	1.1	1.1	1.1	1.1	1.25	1.25
Collapse	1.0	N/A	1.1	N/A	1.1	N/A
Triaxial	1.25	N/A	1.1	N/A	1.25	N/A
Compression	1.4	1.0	1.1	1.0	1.33	1.0

- Casing wear to be considered based on specific well program.
- Triaxial analysis is required for all designs.
- Design factors are applicable to seamless pipe with specified material yield of 125 ksi or lower.
- A collapse design factor of 1.1 is recommended for casing with $10 < D/t < 12$.
- A burst design factor of 1.0 is recommended for surface, intermediate and drilling casing well control designs using gas gradient from shoe fracture pressure.
- It is expected that any deviations will in general be based on a critical review of expected loadings and the risks and mitigations in their control; not on accepting a reduction in design factor.
- Tension design factor is applied to yield of both pipe body and connection critical cross section.
- Refer to GP 10-01, *Casing and Tubing Design Group Practice* [4] for mandatory loads.

4.1 General Comments

Examination of the individual strings is somewhat repetitive, with certain general comments pertinent to all of the checks to follow:

- Tubular design is based on, among other things, differential pressure. The sections to follow,

Table 6. Mississippi Canyon 252 No. 1—Casing Scheme

OD (in)	Type	Hole Size (in)	Measured Depths (ft) Hanger	Shoe	TOC	Mud (ppg)
36	Conductor Casing	36.500	5,081	5,450	5,170	8.7
28	Conductor Casing	32.500	5,081	6,364	5,170	8.6
22	Surface Casing	26.000	5,081	8,089	5,170	10.0
18	Surface Liner	22.000	7,689	9,989	8,989	10.6
16	Intermediate Liner	20.000	5,210	11,585	8,000	11.3
13-5/8	Intermediate Liner	16.000	11,185	13,100	12,600	12.0
11-7/8	Drilling Liner	14.000	12,800	15,300	14,800	13.0
9-7/8	Production Liner	12.250	14,700	17,000	14,700	13.5
7	Production Casing	8.500	5,081	18,250	17,000	13.9

on the other hand, concentrate on the individual differential pressure components of internal and external pressure. In this way the exact source of a deviation in load from default BP practice can be easily detected.

- The final design factor, or safety factor, checks are all performed on a normalized scale. Final design factor is conventionally defined as the quotient of resistance divided by load. If this quantity is then normalized by dividing by the original design factor, then the pass/fail criterion for the limit mode becomes unity.

- The discussion liberally uses the term "burst" when referring to internal pressure loads. "Burst" is a misnomer implying failure due to internal pressure. The actual limit state for internal pressure used both by API and BP is internal yield pressure, that is, the pressure necessary to cause incipient yield of the tube cross section and not catastrophic rupture of the cross section. Recently, API TR 5C3 [2] and ISO TR 10400 [6] introduced both a ductile rupture mode and fracture as additional internal pressure limit states. These catastrophic failure modes are not explicitly used in conventional BP tubular design.

- In several instances there is a slight discrepancy in the Fracture @Shoe w/ Gas Gradient Above well control load due to the use of a simpler model for the gas column by the spreadsheet used to check StressCheck calculations. The spreadsheet uses a constant 0.1 psi/ft gradient from fracture at the shoe of interest, whereas StressCheck uses the ideal gas law to calculate the pressure in the gas column. The symbols representing the calculation by StressCheck should be honored, even though they are usually slightly lower than the spreadsheet values.

- A notable discrepancy between this author's preference and that of the original designer is the density used for the mix fluid when computing burst external pressure back-up for synthetic mud—this author normally uses a value of 7.0 ppg, whereas the original designer used a value of 7.6 ppg. The BP *Tubular Design Manual* recommends "mix fluid" but does not specify a density[7].

  Actually, the 7.0 ppg value preferred by this author, although more conservative than the original designer's value, is also more arbitrary. The original designer's value is based on a high speed centrifuge test performed on a weighted synthetic fluid and represents the minimum density achieved in the experiment[8]. Further, giving due consideration to the fact that a centrifuge does not replicate the more quiescent environment under which solids settling would occur in an actual wellbore, drilling fluids experts have calculated a reasonable lower bound density for an 80–20 synthetic mud of approximately 9 ppg. Regardless of which author's value is selected, the resulting external fluid density will be low and, as noted, difficult to realize except with barite settling. To avoid confusion, in the review the original designer's density of 7.6 ppg has been selected as the mix fluid density of synthetic mud.

- The BP default for temperature in the initial condition is the undisturbed temperature gradient. Identifying the post-cementing temperature with the undisturbed temperature is a common assumption in casing design. It is possible to model the planned cementing operation and waiting time with a thermal simulator such as WellCat. Inasmuch as the actual times associated with a cement job may not correspond to plan, however, for consistency an initial temperature profile equal to the undisturbed temperature is used.

  It is difficult to say whether the strategy of associating the initial temperature profile with the undisturbed temperature is conservative. Typical cementing circulation temperatures will heat the upper part of a casing string and cool the lower part of the string. It is not unusual for these effects to balance resulting in essentially no temperature change (*i.e.*, undisturbed temperature) following cement solidification.

- There are minor discrepancies between two well schematics in the report[9] accompanying the StressCheck file for Mississippi Canyon 252 No. 1. The work below adheres to the first sketch

[7] The density of the base oil used in the drilling fluid at Mississippi Canyon 252 No. 1 was 6.8 ppg.

[8] No documentation is available for the experiment.

[9] "Evaluation of Casing Design Basis for Macondo Prospect, Mississippi Canyon Block 252, OCS-G-32306 Well No.1," Revision 4, Steve Morey, 22 March 2010.

(Figure 2) and the StressCheck file from which it was taken. Although the latter schematic may contain more up-to-date depths (this sketch was completed after the well had spudded), the most current data from the well is addressed in Section 6 involving an as-built check of the design.

- In Table 6 the first three strings have a top-of-cement (5,170 ft) that differs from the hanger depth (5,081 ft). In all likelihood the intent was to cement these strings to the mudline (5,081 ft). The air gap from the rotary kelly bushing to mean sea level is 89 ft. Further note that 5,170 - 5,081 = 89. It appears that the air gap has been counted twice in setting the datum for calculations, resulting in the difference between the top-of-cement of the large diameter outer strings and the mudline. This discrepancy will have negligible effect on the design itself. For consistency, the numbers presented in Table 6 will be honored as if intended by the designer.

- There appears to be a software bug[10] in StressCheck which has affected this design. The Lost Circulation load case uses the current pore pressure distribution to compute the level to which the drilling fluid will drop should a lost circulation condition exist. If, however, the pore pressure distribution is changed during the course of design iterations, StressCheck does not necessarily use the adjusted pore pressure to recompute a new Lost Circulation drilling fluid level. This behavior appears to be the source of several discrepancies between the drilling fluid level calculated in this examination and that existing in the most recent StressCheck file. Nevertheless, it should be noted that (a) in this exercise the discrepancies are duly noted regardless of origin and (b) as discussed in Section 1.2, nowhere is the discrepancy severe enough to endanger the original design calculation.

4.2 Operations Related Issues

In three instances below (see also Section 1.1), the Pressure Test load case was checked, but no test pressure was supplied. This appears to be an oversight. Casing design and installation at BP include a pressure test to a test value close to the maximum load the target string is expected to encounter. As stated in the report[11] accompanying the StressCheck file for Mississippi Canyon 252 No. 1, "The casing pressure test (PT) loads were selected to provide results at or near the worst

[10] A similar issue was reported to Landmark and fixed prior to the writing of this report. The fix, which may also address the discrepancy noted here, appears in the latest patch of EDT 2003.16.1, Patch 2003.16.1.24 (Build 1197) dated December 2, 2009, but not currently loaded on BP's servers. Reference: Email and telephone conversations with Landmark support, July 23 and 26, 2010.

[11] "Evaluation of Casing Design Basis for Macondo Prospect, Mississippi Canyon Block 252, OCS-G-32306 Well No.1," Revision 4, Steve Morey, 22 March 2010.

Table 7. Mississippi Canyon 252 No. 1—Casing Test Pressures

OD (in)	Test Mud (ppg)	Test Pressure (psi)	Setting Mud (ppg)	Comments
28	N/A	N/A	12.0	Cement to mudline
22	8.6	3,455	12.5	Cement to mudline
18	10.1	3,050	10.1	
	10.6	3,000	10.1	
16	11.2	3,600	11.2	11.4 ESD[a]
13-5/8	12.4	2,415	12.4	12.6 ESD[a]
11-7/8	13.4	1,820	13.4	13.6 ESD[a]. 11-7/8 in. (only) saw 5,000 psi when VersaFlex hanger was set.
9-7/8	14.1	914	14.1	14.3 ESD[a]. 9-7/8 in. (only) saw 5,000 psi when VersaFlex hanger was set.
9-7/8 × 7	14.0	2,500	14.0	14.1 ESD[a]. Bottom cement plug blew through with 2,932 psi (entire casing string sees this pressure).

[a]Equivalent static density

case burst load and have not been checked for compliance with any government requirements."

The actual field test pressures to which the casing in Mississippi Canyon 252 No. 1 was subjected are summarized in Table 7. In all cases except the 9-7/8 in. × 7 in. production casing the test pressures exceed those recommended by the BP *Tubular Design Manual*. The production casing was pressure tested to 2,500 psi, with a full pressure test to a tubing leak load probably delayed until the installation of the completion.

4.3 36 in. Conductor

According to Table 2 the conductor casing is designed to meet the following loads[12]:

[12]In addition to its load requirements as a barrier element when drilling the next hole section, the conductor is also required to satisfy axial and lateral structural capacities and fatigue loads associated with its function as the primary foundation for the well and as the interface with surface drilling vessels. These functions are discussed in an overview section of [3] (Subsea Tieback Design), which recommends the drilling well designer seek advice from

1. Running conductor;
2. Cementing (conventional);
3. Pressure test;
4. Lost circulation.

Mississippi Canyon 252 No. 1 was designed for all of the above loads using StressCheck. Figures 2 and 3 compare spreadsheet calculated internal and external pressure profiles, respectively, with the same profiles used by StressCheck in its design calculations. In each figure the solid lines represent the spreadsheet calculated pressures, and the symbols reproduce StressCheck pressures at selected landmarks in the tubular string[13]. StressCheck pressures are determined by linearly interpolating between the landmark values. For both internal and external profiles the StressCheck pressures duplicate those calculated with the spreadsheet, with two exceptions:

1. The internal pressure profile for the Pressure Test load case is parallel to, but higher (500 psi vs. 102 psi at the surface) than that recommended by the BP *Tubular Design Manual* indicating the StressCheck load case to which the 36 in. conductor was designed to be more severe than that recommended by BP design practice.
2. The internal pressure profile for the Lost Circulation load case is parallel to, but slightly higher (40 psi) than that recommended by the BP *Tubular Design Manual* indicating the StressCheck load case to which the 36 in. casing was designed to be slightly less severe than that recommended by BP design practice[14]. This discrepancy should not have serious impact on the design.

.

Points worth noting include the following:

- The discontinuity in the external pressure profile for loads dominated by internal pressure such as the Pressure Test occurs at the top-of-cement (5,170 ft) where the BP burst back-up switches from a fluid column representing either mud or cement mix fluid to local pore pressure.

structural engineering subject matter experts.

[13] The curve used for the Running load case is overlaid by other pressure profiles—internal pressure for the Running load case is identical to the Cementing load case and external pressure for the Running load case is identical to the Lost Circulation load case.

[14] StressCheck uses a slightly different pore pressure in its calculation of fluid level drop. See the last bullet in Section 4.1.

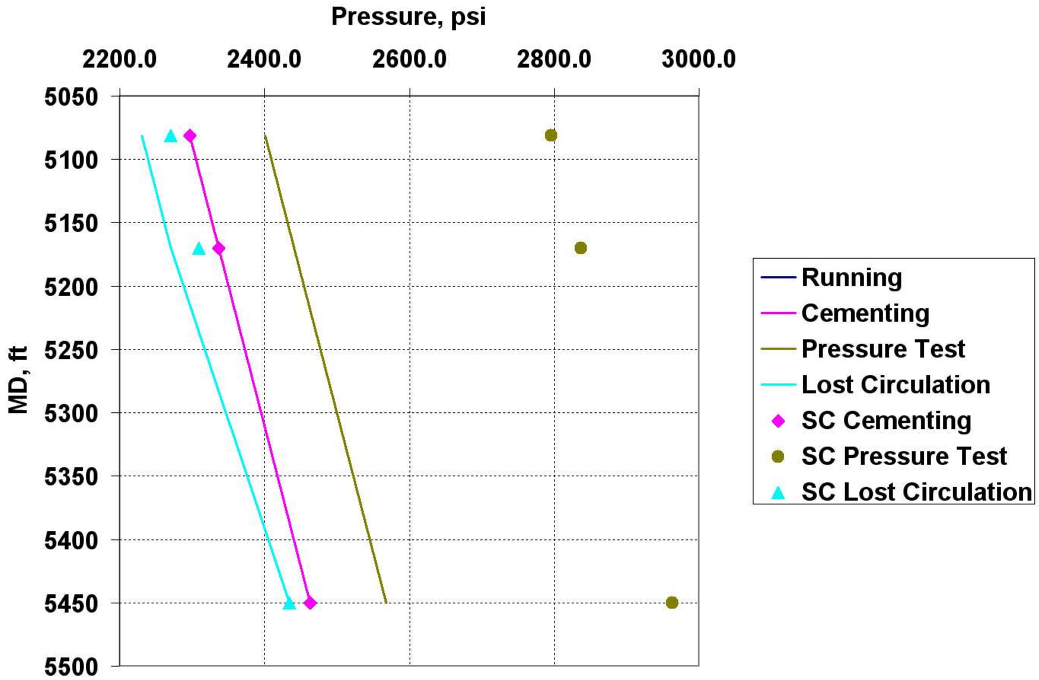

Figure 2. Comparison of Reference [3] and StressCheck Internal Pressure Loads, 36 in. Conductor

- The discontinuity in the slope of the external pressure profile for Cementing occurs at the top-of-cement (5,170 ft) and is due to a change in external fluid density.
- For a conductor the recommended burst back-up fluid (Table 2) is either pore pressure or sea water. In this instance, both the spreadsheet and StressCheck back-ups are slightly more severe, following the recommendations for surface and intermediate casing and using a fresh water gradient above the top-of-cement.

All load cases were associated with the undisturbed temperature profile, implying no temperature change in accordance with Table 2.

Figure 4 is a plot of final design factors[15] as computed by StressCheck for the load cases enumerated above. The abscissa is normalized safety factor in order to view all limit modes on a single plot. All limit modes (internal pressure or "burst", external pressure or collapse, axial yield and triaxial yield) have final design factors above one, indicating an adequate design for the load cases considered.

[15] Often referred to as safety factors.

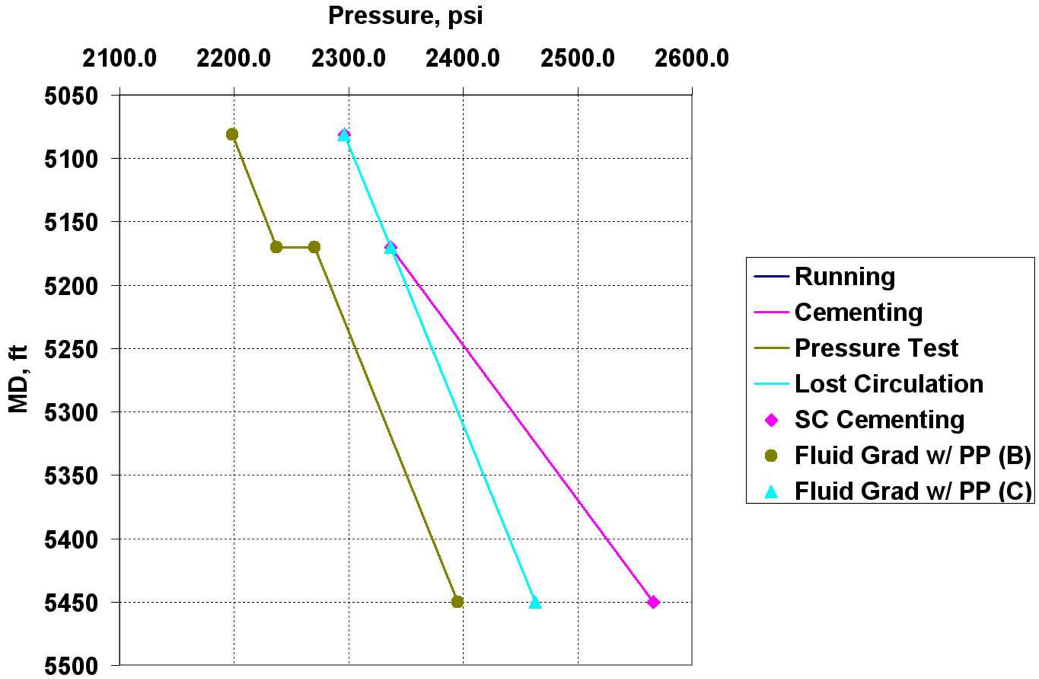

Figure 3. Comparison of Reference [3] and StressCheck External Pressure Loads, 36 in. Conductor, (B) = Burst, (C) = Collapse

4.4 28 in. Conductor

According to Table 2 the conductor casing is designed to meet the following loads:

1. Running conductor;
2. Cementing (conventional);
3. Pressure test;
4. Lost circulation.

Mississippi Canyon 252 No. 1 was designed for all of the above loads using StressCheck. Figures 5 and 6 compare spreadsheet calculated internal and external pressure profiles, respectively, with the same profiles used by StressCheck in its design calculations. In each figure the solid lines represent the spreadsheet calculated pressures, and the symbols reproduce StressCheck pressures at selected landmarks in the tubular string[16]. StressCheck pressures are determined by linearly interpolating

[16] The curve used for the Running load case is overlaid by other pressure profiles—internal pressure for the Running load case is identical to the Cementing load case and external pressure for the Running load case is identical to the

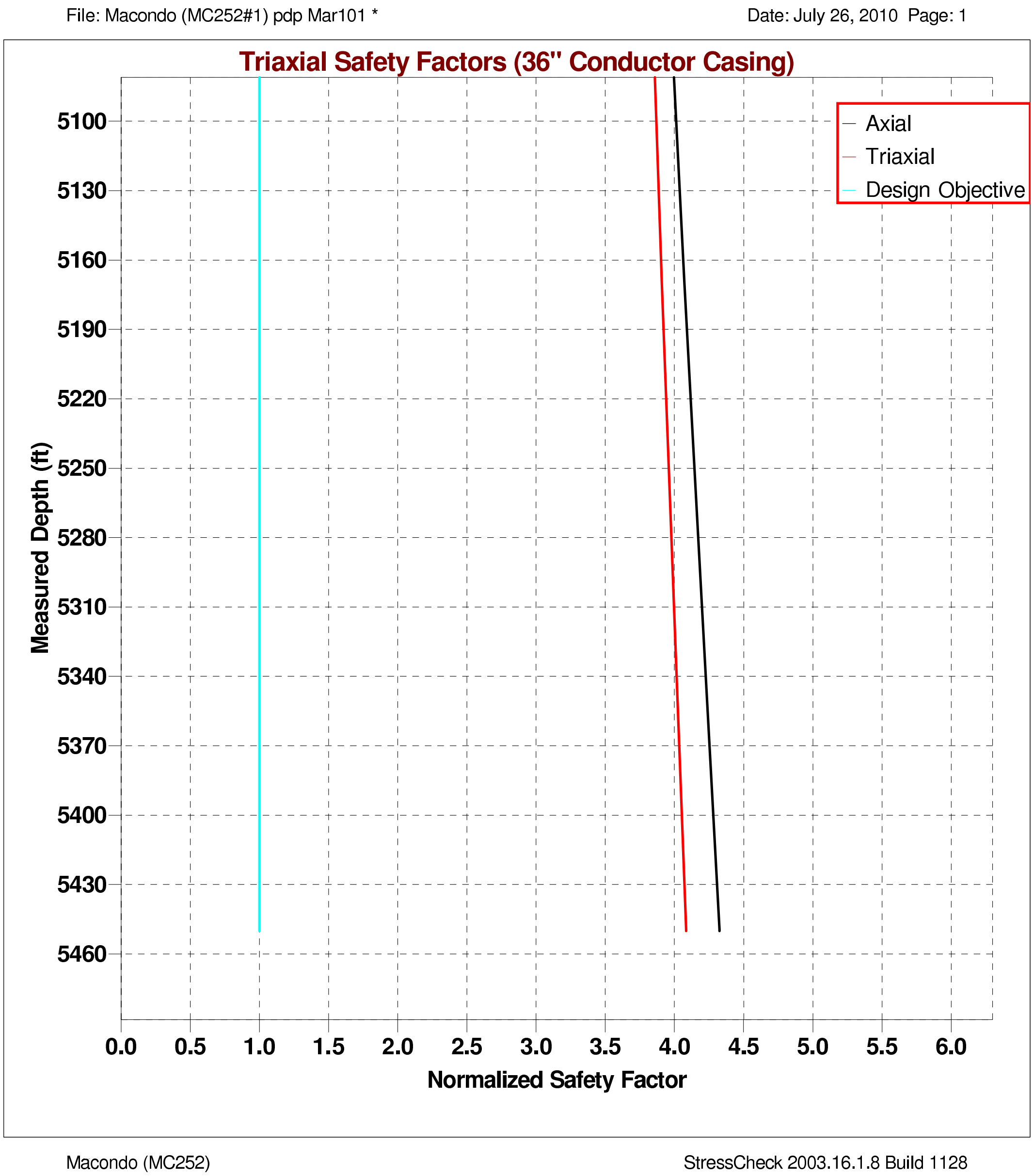

Figure 4. StressCheck Normalized Final Design (Safety) Factors, 36 in. Conductor

between the landmark values. For both internal and external profiles the StressCheck pressures duplicate those calculated with the spreadsheet, with two exceptions:

1. The internal pressure profile for the Pressure Test load case is parallel to, but higher (900 psi

Lost Circulation load case.

vs. 516 psi at the surface) than that recommended by the BP *Tubular Design Manual* indicating the StressCheck load case to which the 28 in. casing was designed to be more severe than that recommended by BP design practice.

2. The internal pressure profile for the Lost Circulation load case is parallel to, but slightly higher (40 psi) than that recommended by the BP *Tubular Design Manual* indicating the StressCheck load case to which the 28 in. casing was designed to be slightly less severe than that recommended by BP design practice[17]. This discrepancy should not have serious impact on the design.

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Points worth noting include the following:

- The discontinuity in the external pressure profile for loads dominated by internal pressure such as the Pressure Test occurs at the previous casing shoe (5,450 ft) where the BP burst back-up switches from a fluid column representing either mud or cement mix fluid to local pore pressure.

- The discontinuity in the slope of the external pressure profile for Cementing occurs at the top-of-cement (5,170 ft) and is due to a change in external fluid density.

- For a conductor the recommended burst back-up fluid (Table 2) is either pore pressure or sea water. In this instance, both the spreadsheet and StressCheck back-ups are slightly more severe, following the recommendations for surface and intermediate casing and using a fresh water gradient above the top-of-cement.

All load cases were associated with the undisturbed temperature profile, implying no temperature change in accordance with Table 2.

Figure 7 is a plot of final design factors as computed by StressCheck for the load cases enumerated above. The abscissa is normalized safety factor in order to view all limit modes on a single plot. All limit modes (internal pressure or "burst", external pressure or collapse, axial yield and triaxial yield) have final design factors above one, indicating an adequate design for the load cases considered. Upon comparison of Figures 7 and 4, the former has several slope discontinuities not appearing in the latter. The StressCheck design load line at any depth is the maximum load (for that limit mode) of all cases considered. Over the length of the tubular, that maximum can vary from one load case to another. The influences of the cement top at 5,170 ft and the previous shoe at 5,450 ft are apparent in the final design factor calculation.

[17]StressCheck uses a slightly different pore pressure in its calculation of fluid level drop. See the last bullet in Section 4.1.

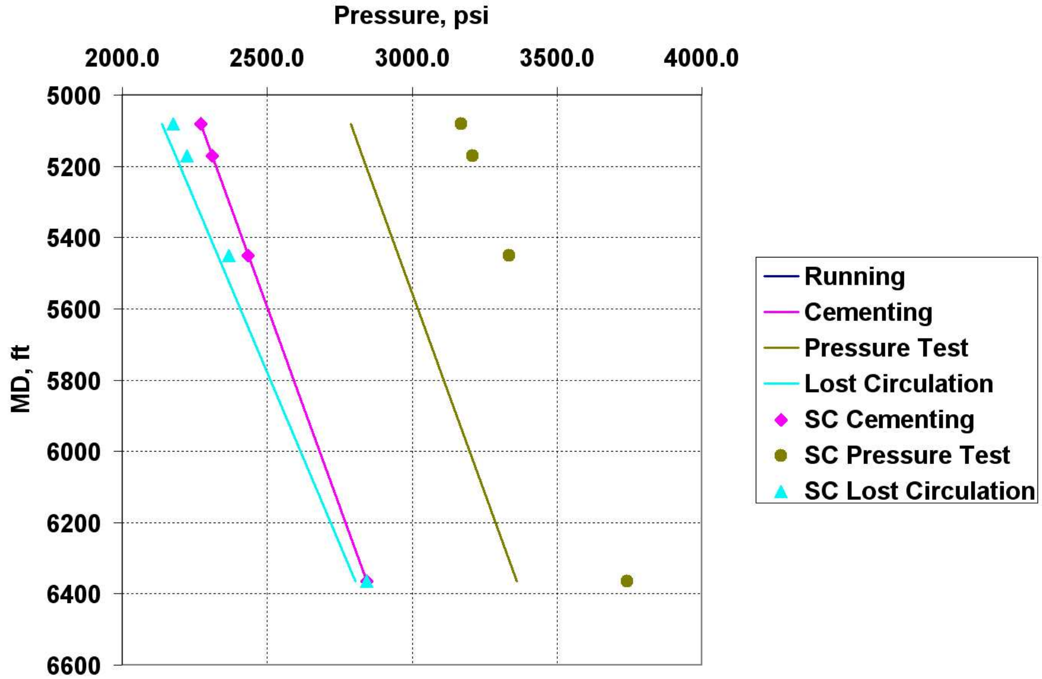

Figure 5. Comparison of Reference [3] and StressCheck Internal Pressure Loads, 28 in. Conductor

4.5 22 in. Surface Casing

According to Table 3 the surface casing is designed to meet the following loads:

1. Running casing;
2. Cementing (conventional);
3. Bumping cement plug[18];
4. Pressure test;
5. Well control, possible hydrocarbon;
6. Lost circulation.

Mississippi Canyon 252 No. 1 was designed for all of the above loads using StressCheck. Figures 8 and 9 compare spreadsheet calculated internal and external pressure profiles, respectively, with the

[18]StressCheck terms this load case Green Cement Pressure Test.

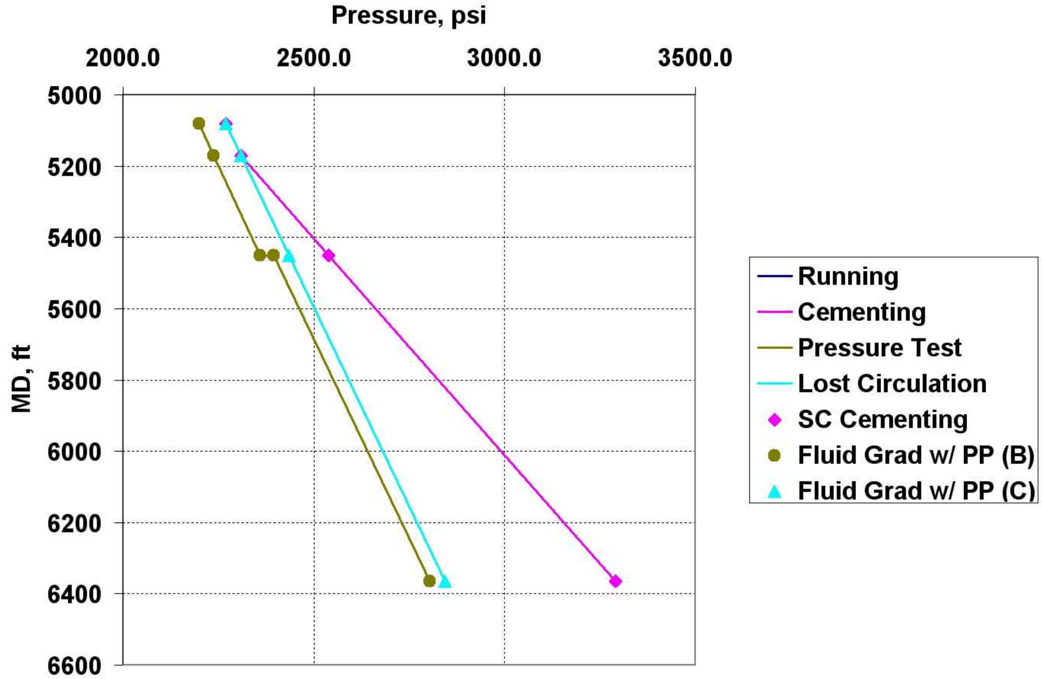

Figure 6. Comparison of Reference [3] and StressCheck External Pressure Loads, 28 in. Conductor, (B) = Burst, (C) = Collapse

same profiles used by StressCheck in its design calculations. In each figure the solid lines represent the spreadsheet calculated pressures, and the symbols reproduce StressCheck pressures at selected landmarks in the tubular string[19]. StressCheck pressures are determined by linearly interpolating between the landmark values. For both internal and external profiles the StressCheck pressures duplicate those calculated with the spreadsheet, with three exceptions.

1. The internal pressure profile for the Pressure Test load case is parallel to, but higher (2,500 psi vs. 623 psi at the surface) than that recommended by the BP *Tubular Design Manual* indicating the StressCheck load case to which the 22 in. casing was designed to be more severe than that recommended by BP design practice.

2. The internal pressure profile for the Lost Circulation load case is parallel to, but lower (168 psi) than that recommended by the BP *Tubular Design Manual* indicating the StressCheck load case to which the 22 in. casing was designed to be more severe than that recommended by

[19] The curve used for the Running load case is overlaid by other pressure profiles—internal pressure for the Running load case is identical to the Cementing load case and external pressure for the Running load case is identical to the Lost Circulation load case.

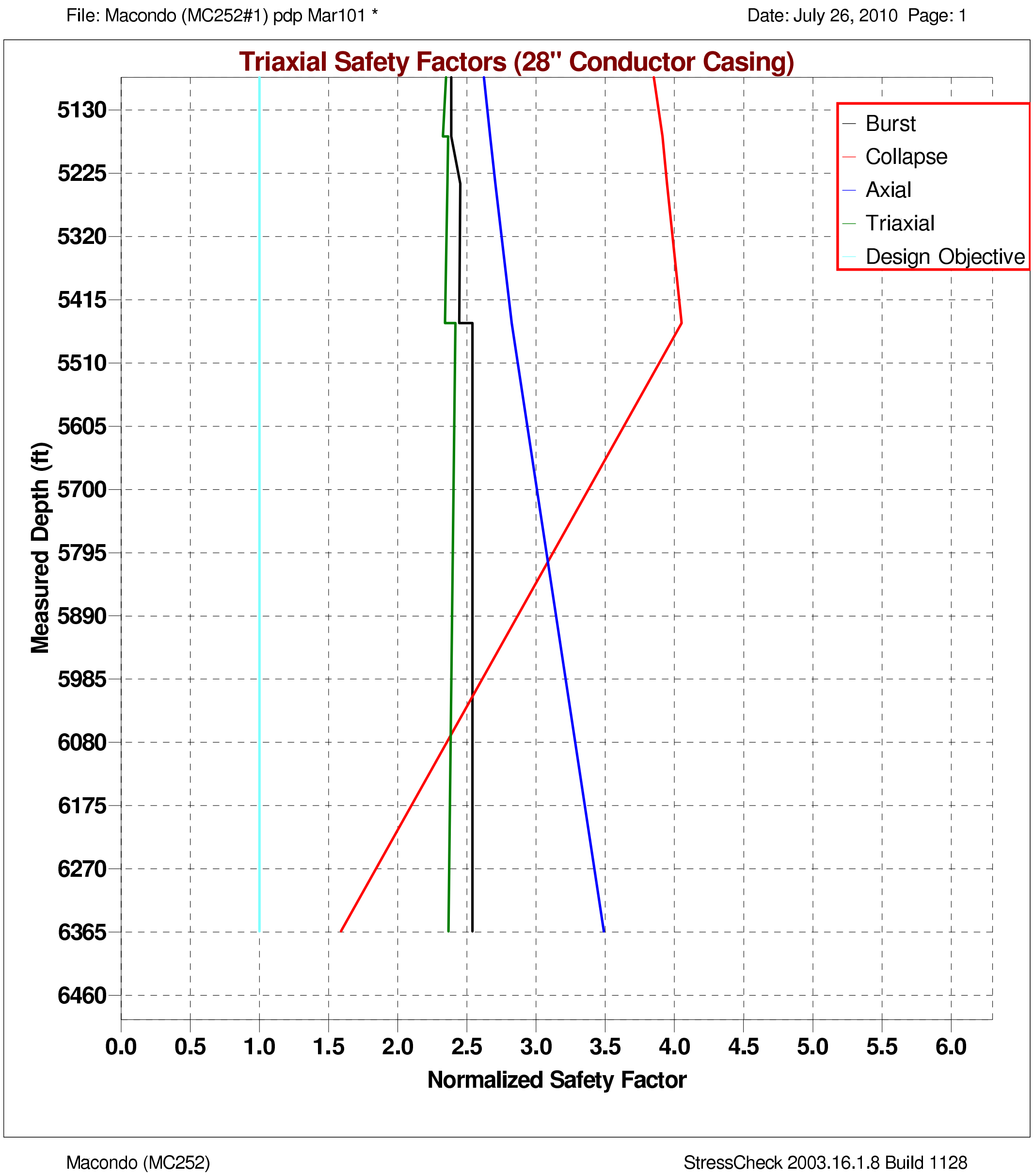

Figure 7. StressCheck Normalized Final Design (Safety) Factors, 28 in. Conductor

BP design practice[20].

[20] It appears that the pore pressure selected by StressCheck, 9.2 ppg at 8,089 ft, was not changed from a previous value of 8.8 ppg, which gives slightly greater mud drop and, therefore, a slightly more conservative collapse load case. See the last bullet in Section 4.1.

3. The starting point for well control design for BP surface and intermediate casing designs is, in StressCheck terminology, Fracture @Shoe w/ Gas Gradient Above. If this load is too onerous a lesser load may be designed for. In this case the lesser load is still substantial—a Gas Kick Profile with a 100 bbl kick volume and 2 ppg kick intensity[21]. This is the load plotted as SC Gas Kick Profile in Figure 8.

   This discrepancy is addressed in a deviation request[22] which replaces the Fracture @Shoe w/ Gas Gradient Above load case with Gas Kick Profile.

   The Fracture @Shoe w/ Gas Gradient Above point of loading in the 22 in. is the exposed extension joint into which the 16 in. supplemental adaptor is installed. Due to the large number of liners in this well, this section of 22 in. casing will experience well control loads down to and including drilling out of the 9-7/8 in. liner. The lighter, lower portion of the tapered 22 in. casing below the 16 in. supplemental adaptor will not be exposed to this high well control loading, although the lower portion of the string will withstand the alternate Gas Kick Profile load (see Figure 10).

   In fact, the lower portion of the string will withstand Fracture @Shoe w/ Gas Gradient Above, as the deepest shoe at which its well control load must be evaluated is the shoe of the 18 in. liner. An additional line (Lower 22 in. WC) illustrates the internal pressure loadings on the upper, heavier and lower portions of the 22 in. casing taken at their respective deepest shoes. For the lighter, lower section the Fracture @Shoe w/ Gas Gradient Above internal pressure is less than that corresponding to a Gas Kick Profile at the 9-7/8 in. liner shoe indicating that the lower section could withstand the starting point BP well control load.

Additional points worth noting include the following:

- The discontinuity in the external pressure profile for loads dominated by internal pressure such as the Pressure Test occurs at the previous conductor shoe (6,364 ft) where the BP burst back-up switches from a fluid column representing either mud or cement mix fluid to local pore pressure.
- The discontinuity in the slope of the external pressure profile for Cementing occurs at the top-of-cement (5,170 ft) and is due to a change in external fluid density.

[21] The severity of the load is further enhanced for BP designs by turning off StressCheck's ability to limit the size of the kick based on the fracture gradient at the casing/liner shoe. For BP designs with limited kick the full kick volume is seen by the casing even if a kick of that volume would fracture the formation at shoe depth.

[22] "22 Burst Dispensation 6-20-2009.docm"

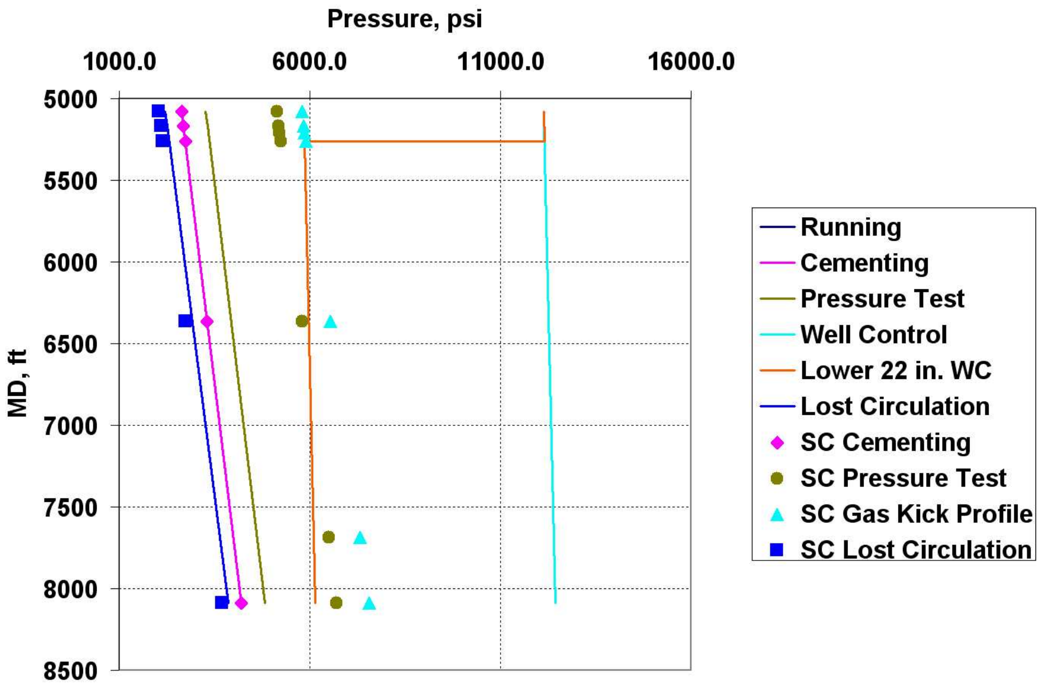

Figure 8. Comparison of Reference [3] and StressCheck Internal Pressure Loads, 22 in. Surface Casing

The load cases in Table 3 labeled "S" and "CMT" are associated with the undisturbed temperature profile, implying no temperature change. Load cases labeled "CT" are associated with a circulating temperature calculated by StressCheck.

Figure 10 is a plot of final design factors as computed by StressCheck for the load cases enumerated above. The abscissa is normalized safety factor in order to view all limit modes on a single plot. All limit modes (internal pressure or "burst", external pressure or collapse, axial yield and triaxial yield) have final design factors above one, indicating an adequate design for the load cases considered. The StressCheck design load line at any depth is the maximum load (for that limit mode) of all cases considered. Over the length of the tubular that maximum can vary from one load case to another. The influences of the crossover between 277.27 lb/ft casing and 224.49 lb/ft casing at 5,264 ft and the previous shoe at 6,364 ft are apparent in the final design factor calculation.

4.6 18 in. Surface Liner

According to Table 3 the surface liner is designed to meet the following loads:

1. Running casing;

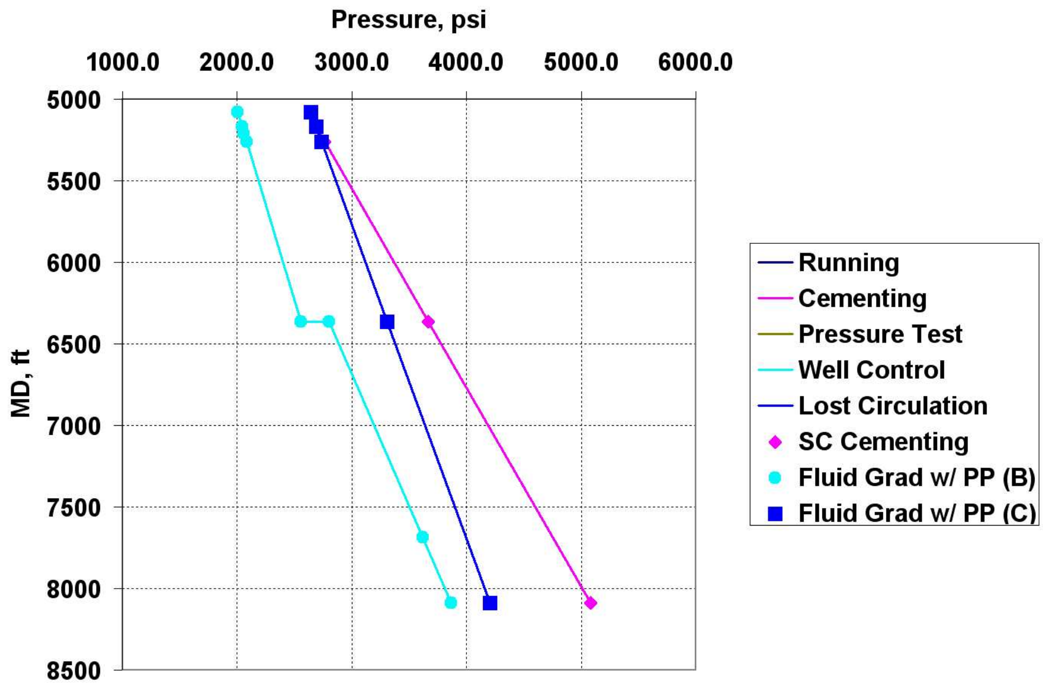

Figure 9. Comparison of Reference [3] and StressCheck External Pressure Loads, 22 in. Surface Casing, (B) = Burst, (C) = Collapse

2. Cementing (conventional);
3. Bumping cement plug[23];
4. Pressure test;
5. Well control, possible hydrocarbon;
6. Lost circulation.

Mississippi Canyon 252 No. 1 was designed for all of the above loads using StressCheck. Figures 11 and 12 compare spreadsheet calculated internal and external pressure profiles, respectively, with the same profiles used by StressCheck in its design calculations. In each figure the solid lines represent the spreadsheet calculated pressures, and the symbols reproduce StressCheck pressures at selected landmarks in the tubular string[24]. StressCheck pressures are determined by linearly

[23]StressCheck terms this load case Green Cement Pressure Test.

[24]The curve used for the Running load case is overlaid by other pressure profiles—internal pressure for the Running load case is identical to the Cementing load case and external pressure for the Running load case is identical to the Lost Circulation load case.

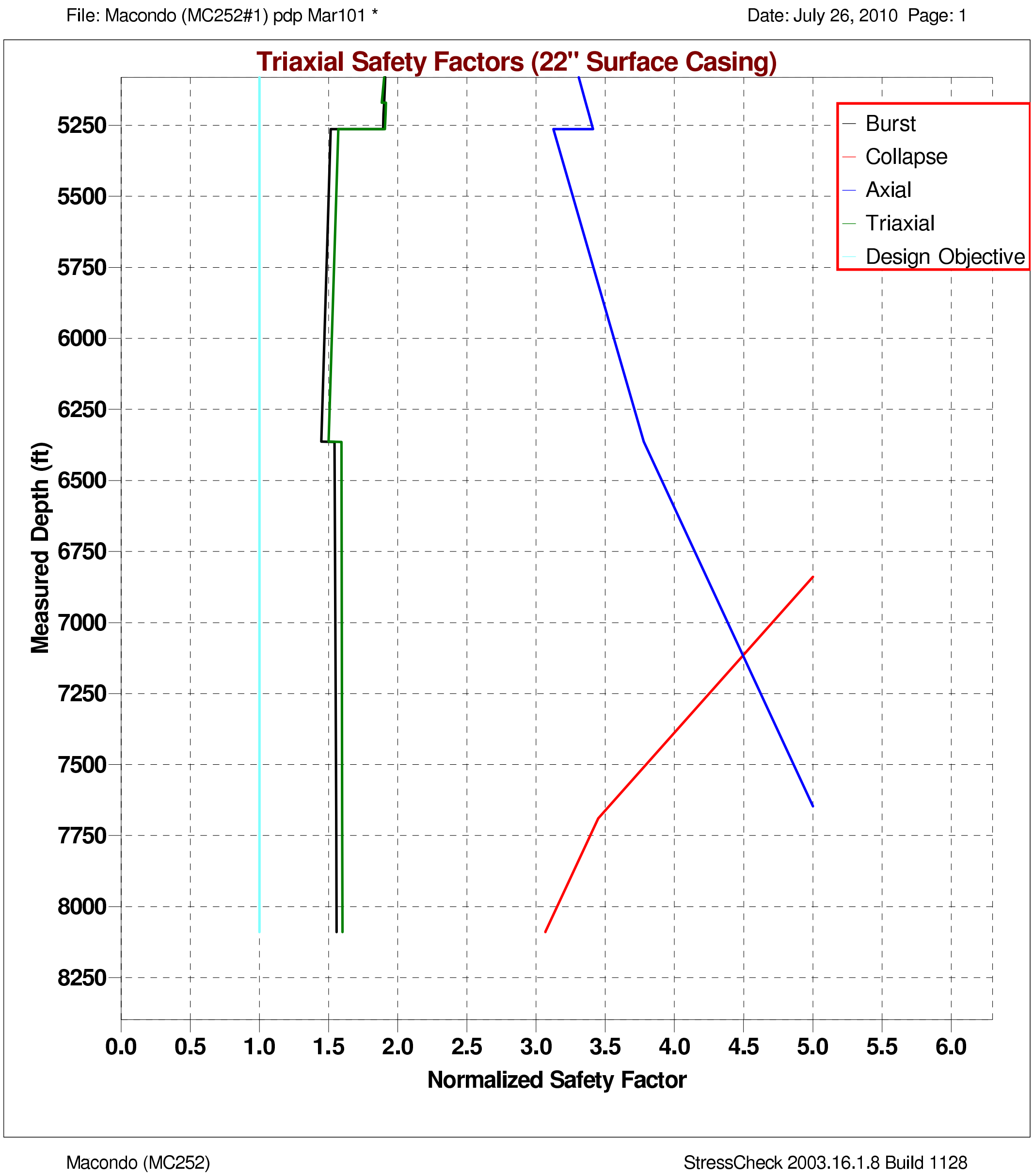

Figure 10. StressCheck Normalized Final Design (Safety) Factors, 22 in. Surface Casing

interpolating between the landmark values. For both internal and external profiles the StressCheck pressures duplicate those calculated with the spreadsheet, with two exceptions.

1. The internal pressure profile for the Pressure Test load case is parallel to, but higher (1,300 psi vs. 1,086 psi at the surface) than that recommended by the BP *Tubular Design Manual* indicating the StressCheck load case to which the 18 in. liner was designed to be more severe

than that recommended by BP design practice.

2. There is a slight discrepancy in the well control load due to the use of a simpler model by the spreadsheet. The symbols representing the calculation by StressCheck should be honored, even though they are slightly lower than the spreadsheet values.

Additional points worth noting include the following:

- The discontinuity in the external pressure profile for loads dominated by internal pressure such as the Pressure Test occurs at the top-of-cement (8,989 ft) where the BP burst back-up switches from a fluid column representing either mud or cement mix fluid to local pore pressure.
- The discontinuity in the slope of the external pressure profile for Cementing occurs at the top-of-cement (8,989 ft) and is due to a change in external fluid density.

The load cases in Table 3 labeled “S” and “CMT” are associated with the undisturbed temperature profile, implying no temperature change. Load cases labeled “CT” are associated with a circulating temperature calculated by StressCheck.

Figure 13 is a plot of final design factors as computed by StressCheck for the load cases enumerated above. The abscissa is normalized safety factor in order to view all limit modes on a single plot. All limit modes (internal pressure or “burst”, external pressure or collapse, axial yield and triaxial yield) have final design factors above one, indicating an adequate design for the load cases considered. The StressCheck design load line at any depth is the maximum load (for that limit mode) of all cases considered. Over the length of the tubular that maximum can vary from one load case to another. The influences of the cement top at 8,989 ft and the previous shoe at 8,089 ft are apparent in the final design factor calculation.

4.7 16 in. Intermediate Liner

According to Table 3 the intermediate liner is designed to meet the following loads:

1. Running casing;
2. Cementing (conventional);
3. Bumping cement plug[25];
4. Pressure test;

[25] StressCheck terms this load case Green Cement Pressure Test.

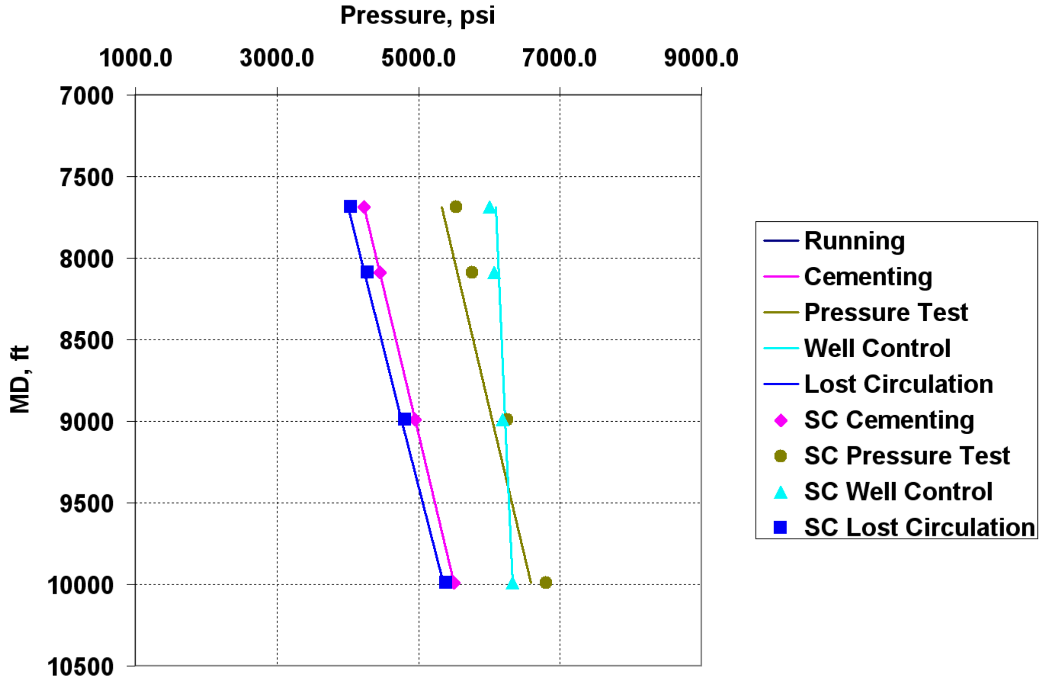

Figure 11. Comparison of Reference [3] and StressCheck Internal Pressure Loads, 18 in. Surface Liner

5. Well control, possible hydrocarbon;

6. Lost circulation.

Mississippi Canyon 252 No. 1 was designed for all of the above loads using StressCheck. Figures 14 and 15 compare spreadsheet calculated internal and external pressure profiles, respectively, with the same profiles used by StressCheck in its design calculations. In each figure the solid lines represent the spreadsheet calculated pressures, and the symbols reproduce StressCheck pressures at selected landmarks in the tubular string[26]. StressCheck pressures are determined by linearly interpolating between the landmark values. For both internal and external profiles the StressCheck pressures duplicate those calculated with the spreadsheet, with three exceptions.

1. The internal pressure profile for the Pressure Test load case is absent from the design of this string. This appears to be an inadvertent load case omission.

[26] The curve used for the Running load case is overlaid by other pressure profiles—internal pressure for the Running load case is identical to the Cementing load case and external pressure for the Running load case is identical to the Lost Circulation load case.

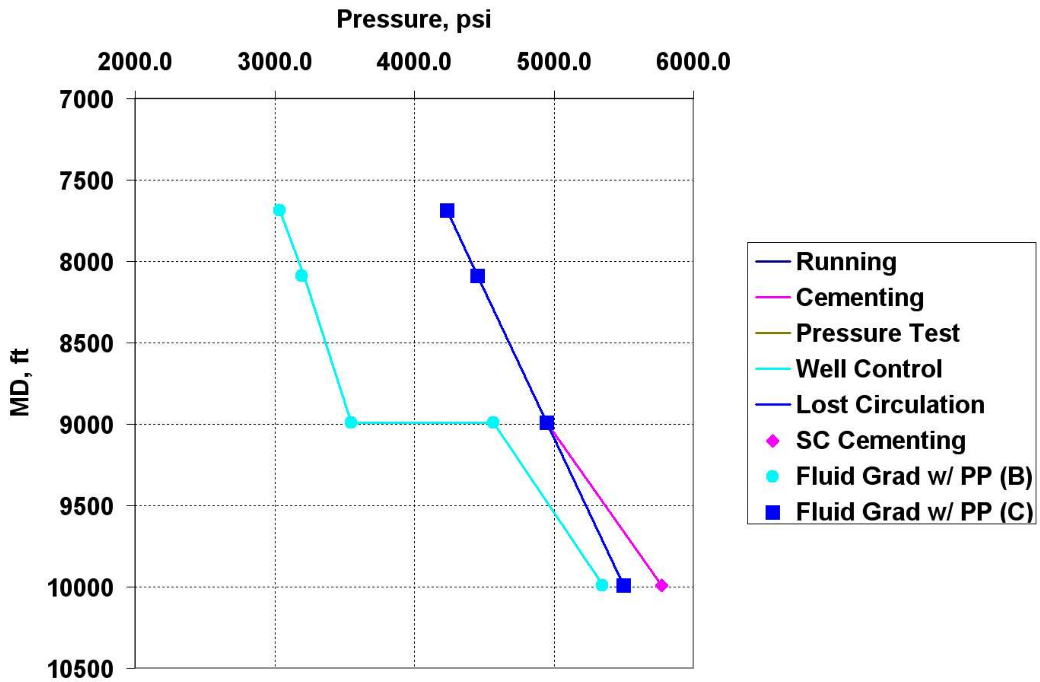

Figure 12. Comparison of Reference [3] and StressCheck External Pressure Loads, 18 in. Surface Liner, (B) = Burst, (C) = Collapse

2. The internal pressure profile for the Lost Circulation load case is parallel to, but slightly higher (291 psi) than that recommended by the BP *Tubular Design Manual* indicating the StressCheck load case to which the 16 in. casing was designed to be slightly less severe than that recommended by BP design practice[27].

3. The starting point for well control design for BP surface and intermediate casing designs is, in StressCheck terminology, Fracture @Shoe w/ Gas Gradient Above. If this load is too onerous a lesser load may be designed for. In this case the lesser load is still substantial—a Gas Kick Profile with a 100 bbl kick volume and 2 ppg kick intensity. This is the load plotted as SC Gas Kick Profile in Figure 14.

   This discrepancy is addressed in a deviation request[28] which replaces the Fracture @Shoe w/ Gas Gradient Above load case with Gas Kick Profile.

[27] It appears that the pore pressure selected by StressCheck, 11.12 ppg at 11,585 ft, was not changed from a previous value of 11.6 ppg, which gives slightly smaller mud drop and, therefore, a slightly less conservative collapse load case. See the last bullet in Section 4.1.

[28] "16 Burst Dispensation 6-20-2009.docm"

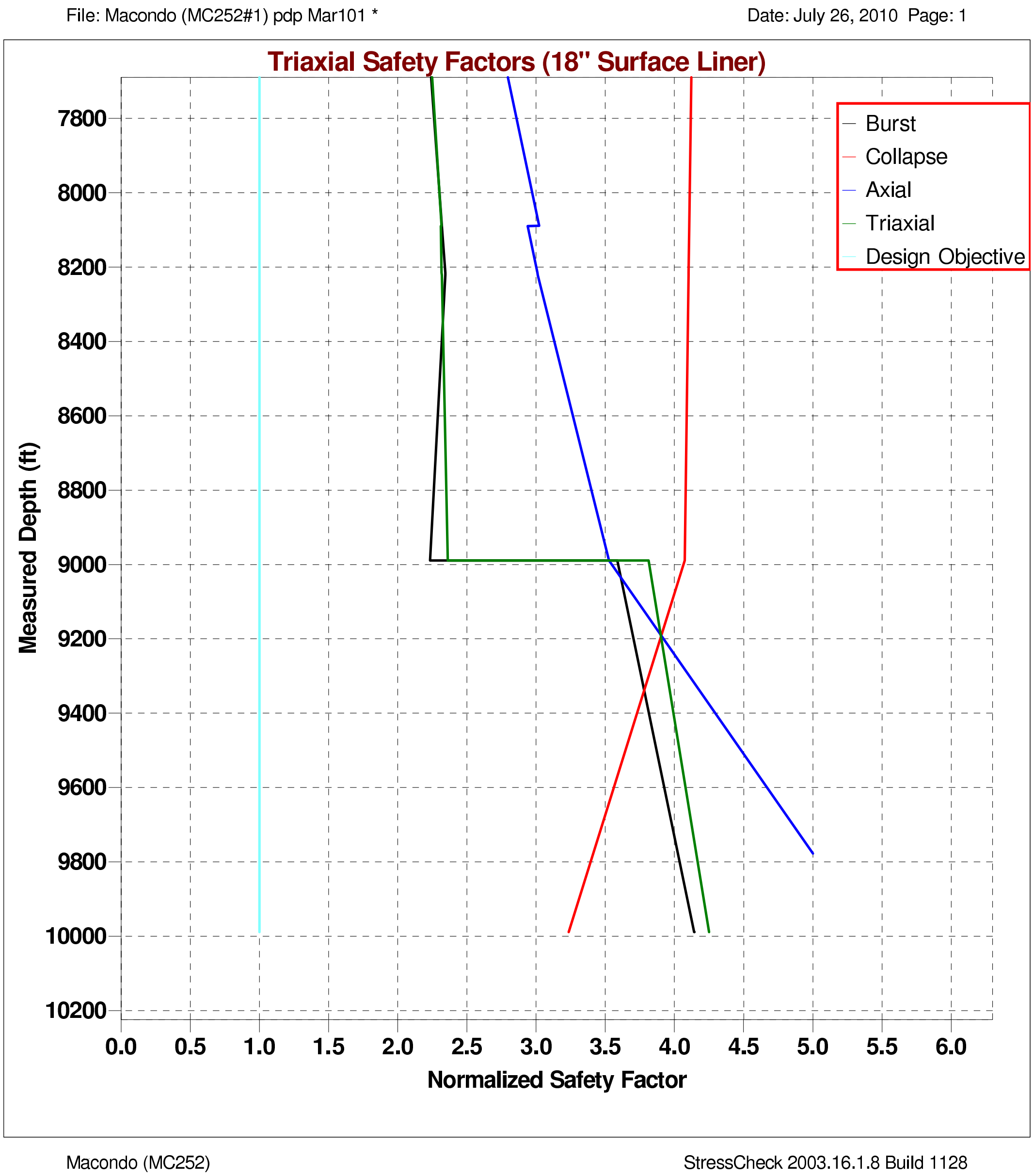

Figure 13. StressCheck Normalized Final Design (Safety) Factors, 18 in. Surface Liner

Additional points worth noting include the following:

- The discontinuity in the external pressure profile for loads dominated by internal pressure such as the Pressure Test occurs at the previous casing shoe (9,989 ft) where the BP burst back-up switches from a fluid column representing either mud or cement mix fluid to local pore pressure.

- The discontinuity in the slope of the external pressure profile for Cementing occurs at the top-of-cement (8,000 ft) and is due to a change in external fluid density.

The load cases in Table 3 labeled “S” and “CMT” are associated with the undisturbed temperature profile[29], implying no temperature change. Load cases labeled “CT” are associated with a circulating temperature calculated by StressCheck.

Figure 16 is a plot of final design factors as computed by StressCheck for the load cases enumerated above. The abscissa is normalized safety factor in order to view all limit modes on a single plot. All limit modes (internal pressure or “burst”, external pressure or collapse, axial yield and triaxial yield) have final design factors above one, indicating an adequate design for the load cases considered, with one exception (see below). The StressCheck design load line at any depth is the maximum load (for that limit mode) of all cases considered. Over the length of the tubular that maximum can vary from one load case to another. The influences of the cement top at 8,000 ft and the previous shoe at 9,989 ft are apparent in the final design factor calculation.

The Gas Kick Profile governing the burst design factor has a final burst design factor of 1.06 as compared to a minimum acceptable value of 1.10. The region over which this shortfall occurs is within the previous casing string, suggesting that the consequences of accepting this design might be mitigated by the backing of both cement and the previous casing string, although this is not standard BP design practice. It is worth noting that the triaxial design factor is acceptable for all load cases at all depths.

4.8 13-5/8 in. Intermediate Liner

According to Table 3 the intermediate liner is designed to meet the following loads:

1. Running casing;
2. Cementing (conventional);
3. Bumping cement plug[30];
4. Pressure test;
5. Well control, possible hydrocarbon;

[29]For this string the Green Cement Pressure Test uses a slightly different temperature profile than undisturbed, but this should have minimal impact on design calculations. The Green Cement Pressure Test models bumping the cement plug and is usually not a governing load case as, in the absence of axial constraint while the cement is unset, the only effect of temperature is adjustment of the tube material yield stress. Similar comments apply to the Cementing load case whose temperature profile also differs slightly from undisturbed.

[30]StressCheck terms this load case Green Cement Pressure Test.

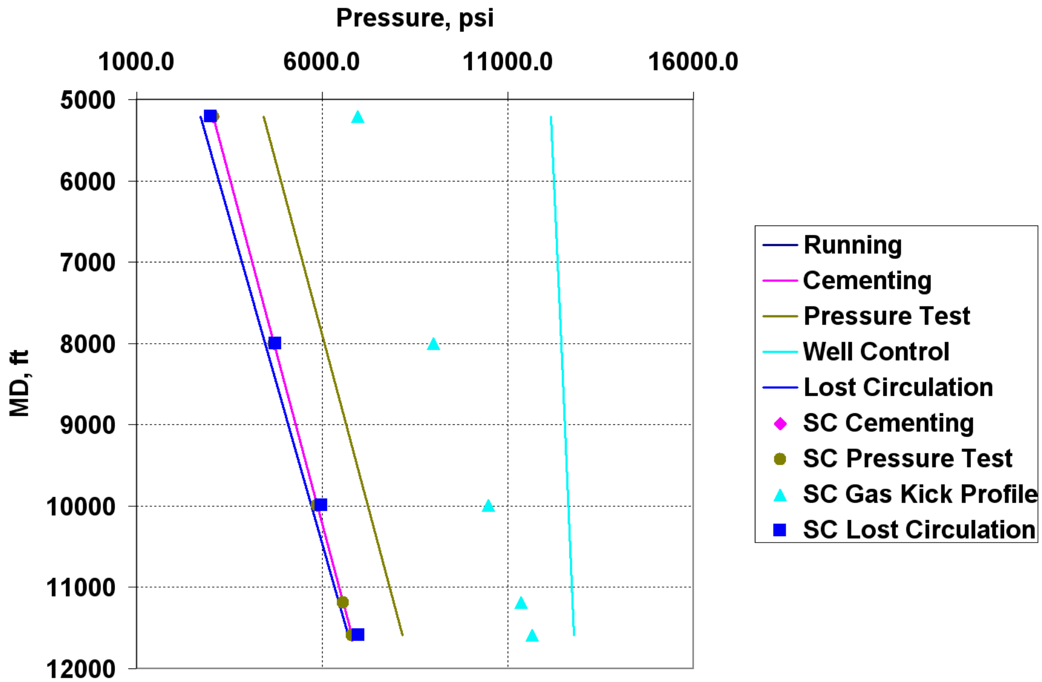

Figure 14. Comparison of Reference [3] and StressCheck Internal Pressure Loads, 16 in. Intermediate Liner

6. Lost circulation.

Mississippi Canyon 252 No. 1 was designed for all of the above loads using StressCheck. Figures 17 and 18 compare spreadsheet calculated internal and external pressure profiles, respectively, with the same profiles used by StressCheck in its design calculations. In each figure the solid lines represent the spreadsheet calculated pressures, and the symbols reproduce StressCheck pressures at selected landmarks in the tubular string[31]. StressCheck pressures are determined by linearly interpolating between the landmark values. For both internal and external profiles the StressCheck pressures duplicate those calculated with the spreadsheet, with three exceptions.

1. The internal pressure profile for the Pressure Test load case is parallel to, but higher (3,500 psi vs. 1,525 psi at the surface) than that recommended by the BP *Tubular Design Manual* indicating the StressCheck load case to which the 13-5/8 in. liner was designed to be more severe than that recommended by BP design practice.

[31] The curve used for the Running load case is overlaid by other pressure profiles—internal pressure for the Running load case is identical to the Cementing load case and external pressure for the Running load case is identical to the Lost Circulation load case.

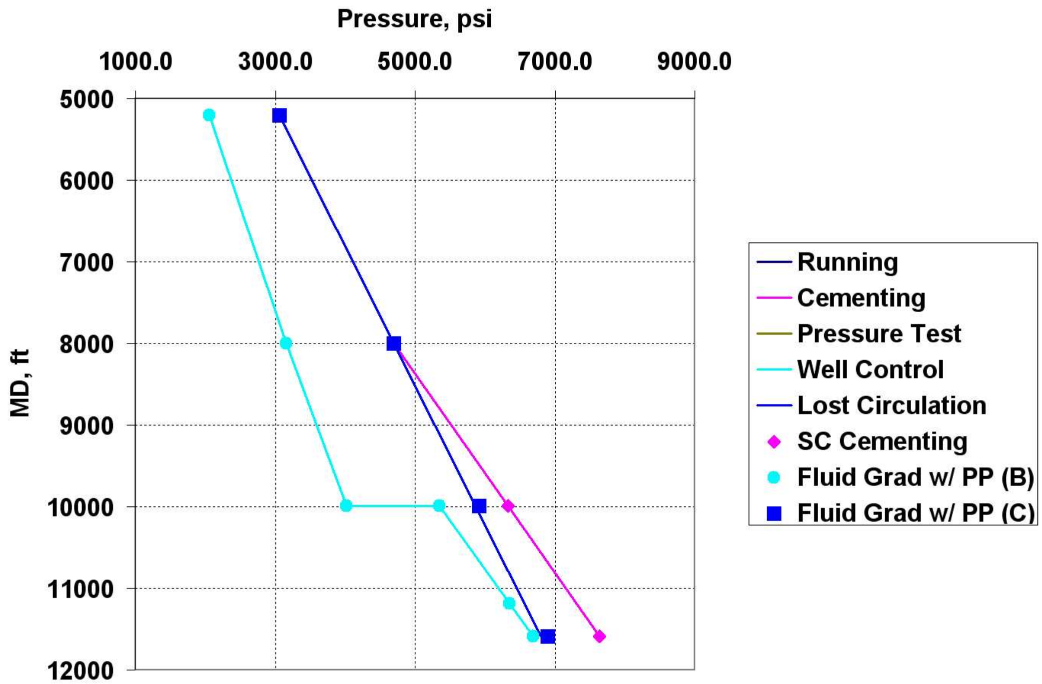

Figure 15. Comparison of Reference [3] and StressCheck External Pressure Loads, 16 in. Intermediate Liner, (B) = Burst, (C) = Collapse

2. There is a slight discrepancy in the well control load due to the use of a simpler model by the spreadsheet. The symbols representing the calculation by StressCheck should be honored, even though they are slightly lower than the spreadsheet values.

3. The internal pressure profile for Lost Circulation is parallel to, but higher (748 psi) than that recommended by the BP *Tubular Design Manual* indicating the StressCheck load case to which the 13-5/8 in. liner was designed to be less severe than that recommended by BP design practice[32].

Additional points worth noting include the following:

- The discontinuity in the external pressure profile for loads dominated by internal pressure such as the Pressure Test occurs at the top-of-cement (12,600 ft) where the BP burst back-up switches from a fluid column representing either mud or cement mix fluid to local pore pressure.

[32]It appears that the pore pressure selected by StressCheck, 11.8 ppg at 13,100 ft, was not changed from a previous value of 12.9 ppg, which gives slightly smaller mud drop and, therefore, a slightly less conservative collapse load case. See the last bullet in Section 4.1.

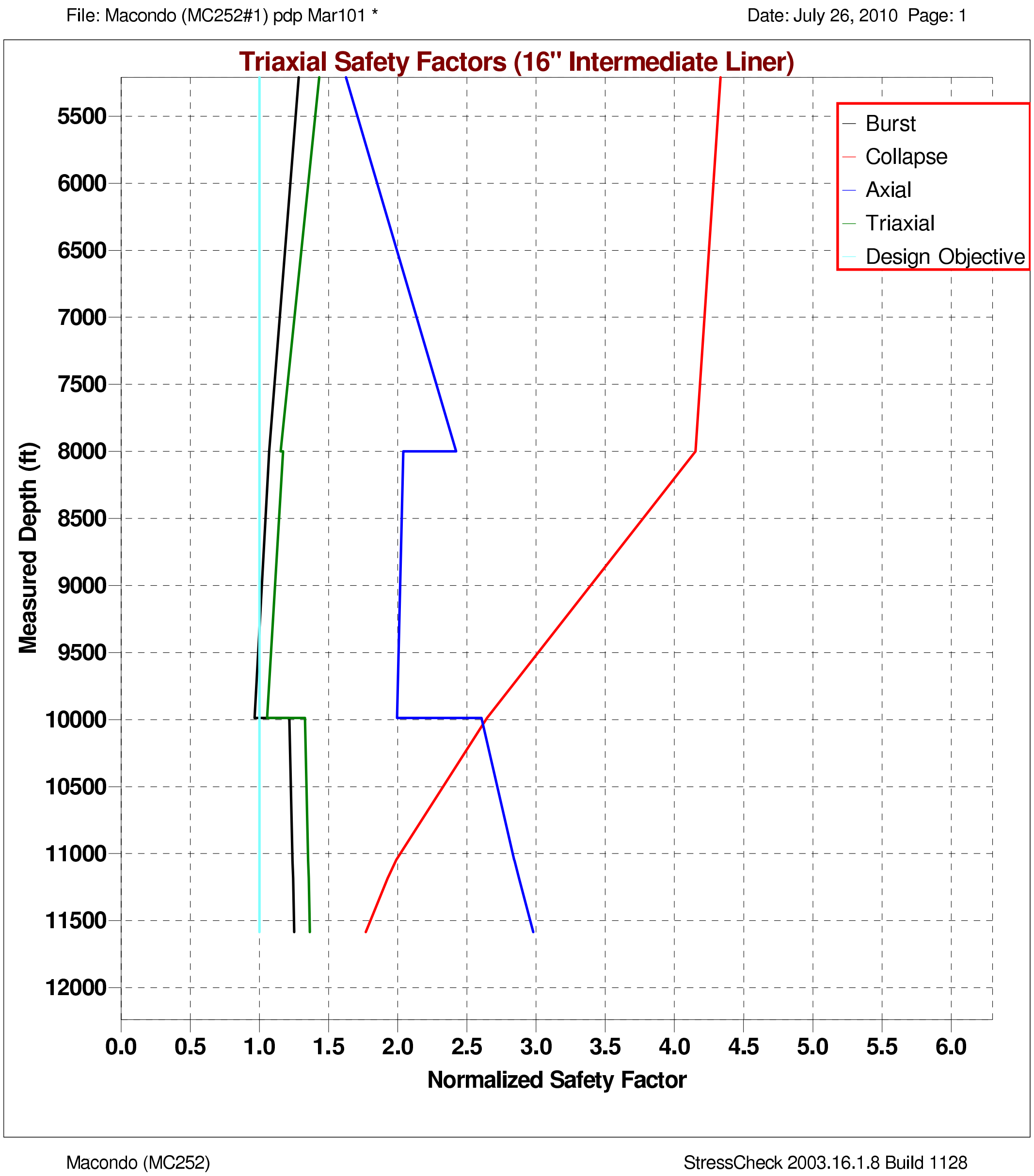

Figure 16. StressCheck Normalized Final Design (Safety) Factors, 16 in. Intermediate Liner

- The discontinuity in the slope of the external pressure profile for Cementing occurs at the top-of-cement (12,600 ft) and is due to a change in external fluid density.

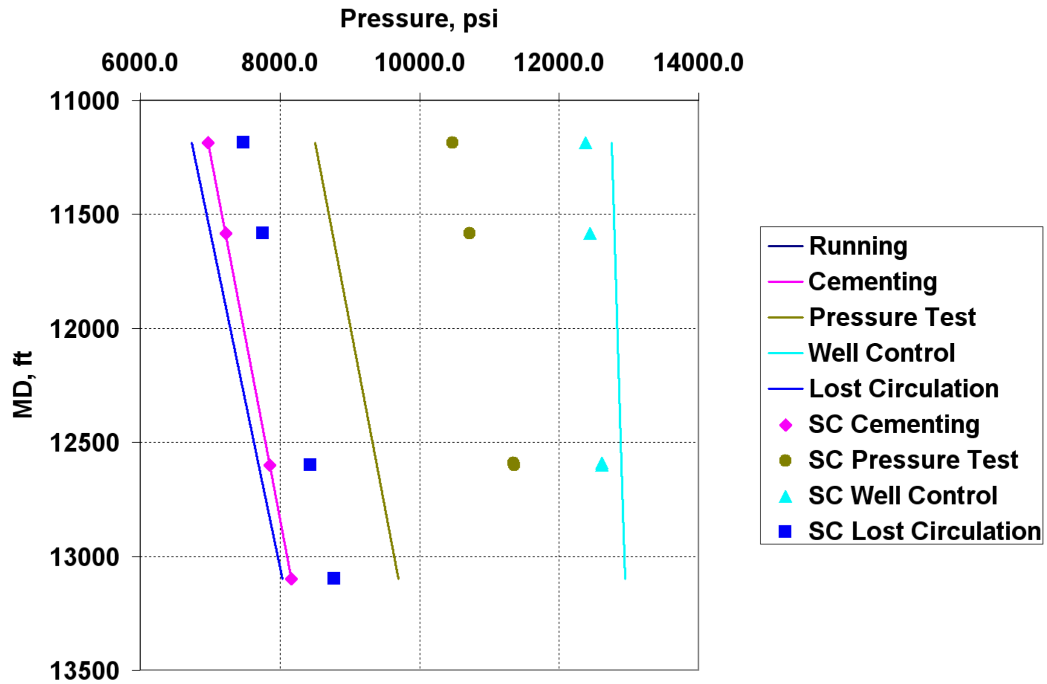

Figure 17. Comparison of Reference [3] and StressCheck Internal Pressure Loads, 13-5/8 in. Intermediate Liner

The load cases in Table 3 labeled "S" and "CMT" are associated with the undisturbed temperature profile[33], implying no temperature change. Load cases labeled "CT" are associated with a circulating temperature calculated by StressCheck.

Figure 19 is a plot of final design factors as computed by StressCheck for the load cases enumerated above. The abscissa is normalized safety factor in order to view all limit modes on a single plot. All limit modes (internal pressure or "burst", external pressure or collapse, axial yield and triaxial yield) have final design factors above one, indicating an adequate design for the load cases considered. The StressCheck design load line at any depth is the maximum load (for that limit mode) of all cases considered. Over the length of the tubular that maximum can vary from one load case to another. The influences of the cement top at 12,600 ft and the previous shoe at 11,585 ft are apparent in the final design factor calculation.

[33]For this string the Green Cement Pressure Test uses a slightly different temperature profile than undisturbed, but this should have minimal impact on design calculations. The Green Cement Pressure Test models bumping the cement plug and is usually not a governing load case as, in the absence of axial constraint while the cement is unset, the only effect of temperature is adjustment of the tube material yield stress. Similar comments apply to the Cementing load case whose temperature profile also differs slightly from undisturbed.

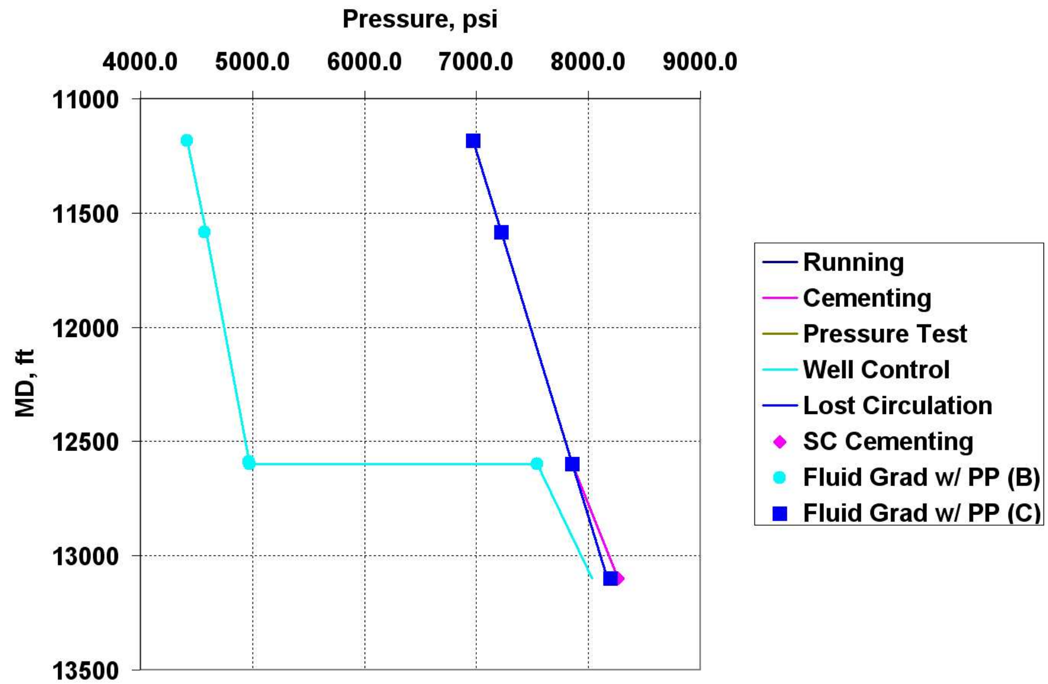

Figure 18. Comparison of Reference [3] and StressCheck External Pressure Loads, 13-5/8 in. Intermediate Liner, (B) = Burst, (C) = Collapse

4.9 11-7/8 in. Drilling Liner

According to Table 3 the drilling (*i.e.*, intermediate) liner is designed to meet the following loads:

1. Running casing;
2. Cementing (conventional);
3. Bumping cement plug[34];
4. Pressure test;
5. Well control, possible hydrocarbon;
6. Lost circulation.

Mississippi Canyon 252 No. 1 was designed for all of the above loads using StressCheck. Figures 20 and 21 compare spreadsheet calculated internal and external pressure profiles, respectively,

[34]StressCheck terms this load case Green Cement Pressure Test.

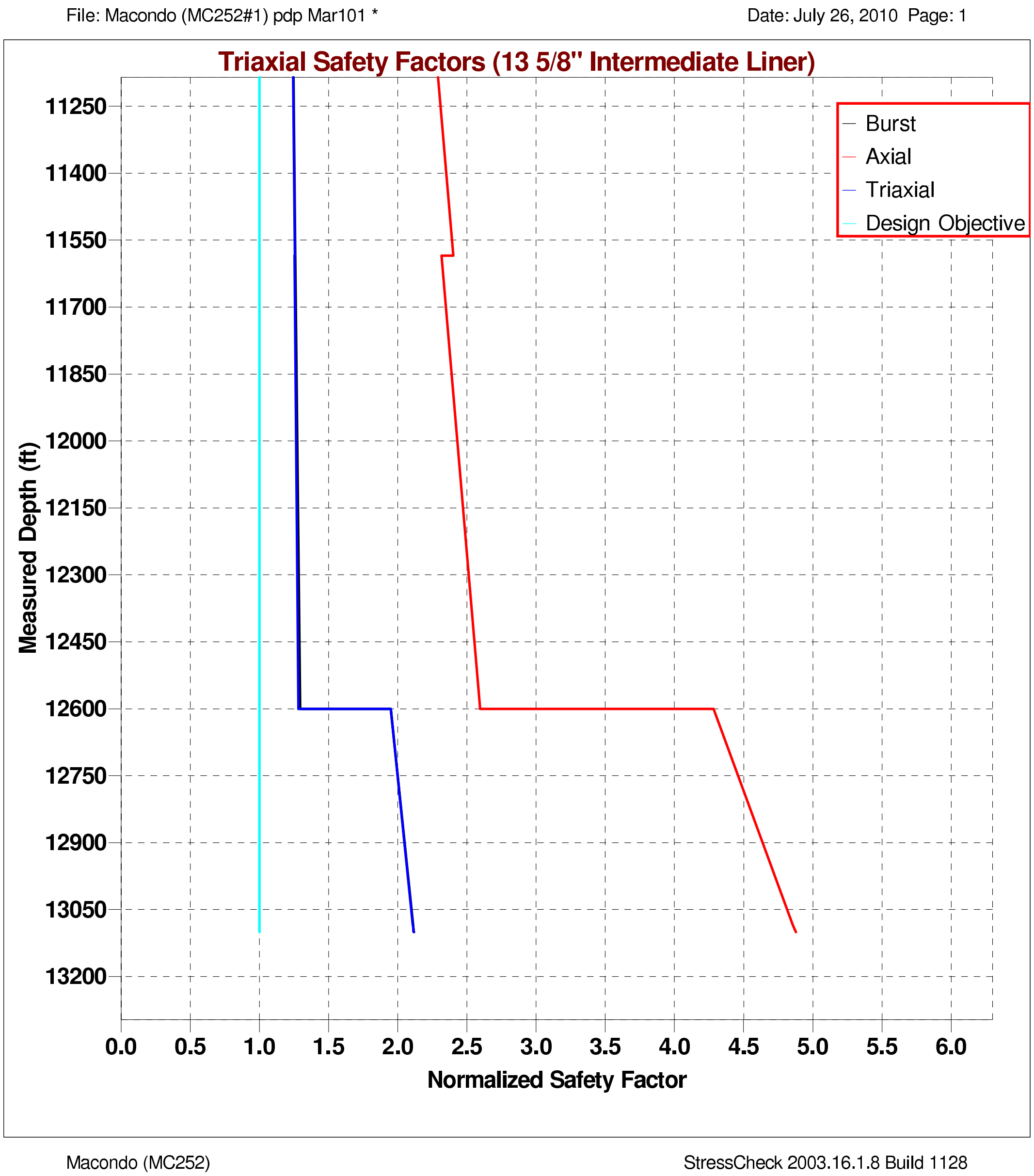

Figure 19. StressCheck Normalized Final Design (Safety) Factors, 13-5/8 in. Intermediate Liner

with the same profiles used by StressCheck in its design calculations. In each figure the solid lines represent the spreadsheet calculated pressures, and the symbols reproduce StressCheck pressures at selected landmarks in the tubular string[35]. StressCheck pressures are determined by linearly

[35]The curve used for the Running load case is overlaid by other pressure profiles—internal pressure for the Running load case is identical to the Cementing load case and external pressure for the Running load case is identical to the

interpolating between the landmark values. For both internal and external profiles the StressCheck pressures duplicate those calculated with the spreadsheet, with three exceptions.

1. The internal pressure profile for the Pressure Test load case is parallel to, but higher (2,000 psi vs. 1,656 psi at the surface) than that recommended by the BP *Tubular Design Manual* indicating the StressCheck load case to which the 11-7/8 in. liner was designed to be more severe than that recommended by BP design practice.

2. There is a slight discrepancy in the well control load due to the use of a simpler model by the spreadsheet. The symbols representing the calculation by StressCheck should be honored, even though they are slightly lower than the spreadsheet values.

3. The internal pressure profile for Lost Circulation is parallel to, but slightly higher (322 psi) than that recommended by the BP *Tubular Design Manual* indicating the StressCheck load case to which the 11-7/8 in. liner was designed to be slightly less severe than that recommended by BP design practice[36].

Additional points worth noting include the following:

- The discontinuity in the external pressure profile for loads dominated by internal pressure such as the Pressure Test occurs at the top-of-cement (14,800 ft) where the BP burst backup switches from a fluid column representing either mud or cement mix fluid to local pore pressure.

- The discontinuity in the slope of the external pressure profile for Cementing occurs at the top-of-cement (14,800 ft) and is due to a change in external fluid density.

The load cases in Table 3 labeled "S" and "CMT" are associated with the undisturbed temperature profile[37], implying no temperature change. Load cases labeled "CT" are associated with a circulating temperature calculated by StressCheck.

Lost Circulation load case.

[36]It appears that the pore pressure selected by StressCheck, 12.8 ppg at 15,300 ft, was not changed from a previous value of 13.4 ppg, which gives slightly smaller mud drop and, therefore, a slightly less conservative collapse load case. See the last bullet in Section 4.1. This is partially mitigated by the use of 14.6 ppg mud density rather than 13.5 ppg as indicated on the StressCheck Casing and Tubing Scheme spreadsheet.

[37]For this string the Green Cement Pressure Test uses a slightly different temperature profile than undisturbed, but this should have minimal impact on design calculations. The Green Cement Pressure Test models bumping the cement plug and is usually not a governing load case as, in the absence of axial constraint while the cement is unset, the only effect of temperature is adjustment of the tube material yield stress. Similar comments apply to the Cementing load case whose temperature profile also differs slightly from undisturbed.

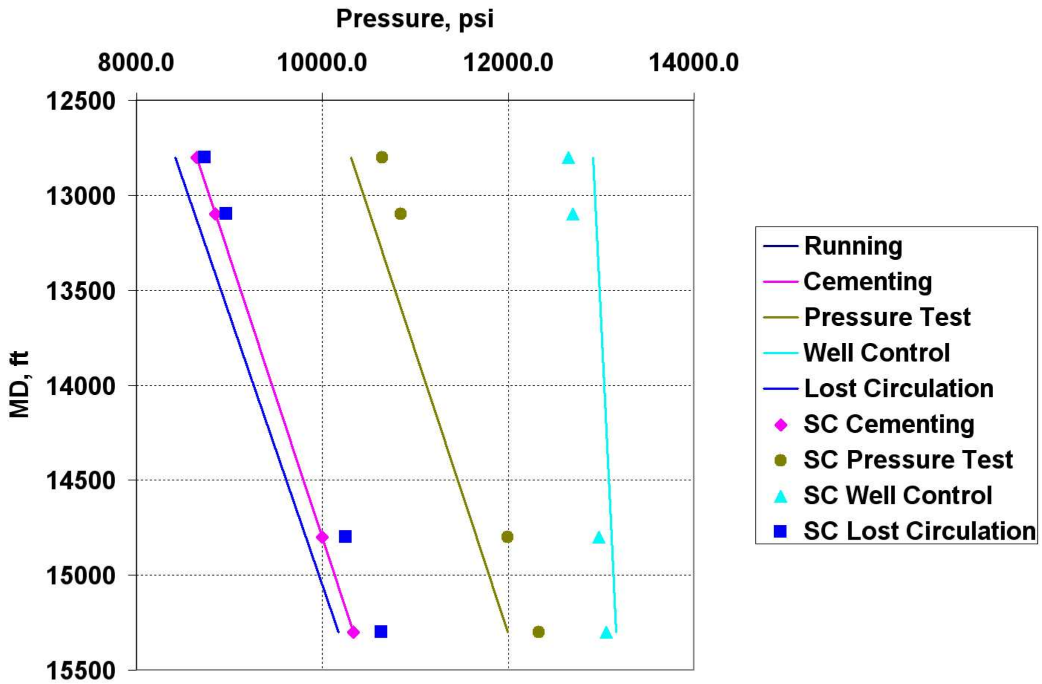

Figure 20. Comparison of Reference [3] and StressCheck Internal Pressure Loads, 11-7/8 in. Drilling Liner

Figure 22 is a plot of final design factors as computed by StressCheck for the load cases enumerated above. The abscissa is normalized safety factor in order to view all limit modes on a single plot. All limit modes (internal pressure or "burst", external pressure or collapse, axial yield and triaxial yield) have final design factors above one, indicating an adequate design for the load cases considered. The StressCheck design load line at any depth is the maximum load (for that limit mode) of all cases considered. Over the length of the tubular that maximum can vary from one load case to another. The influences of the cement top at 14,800 ft and the previous shoe at 13,100 ft are apparent in the final design factor calculation.

4.10 9-7/8 in. Production Liner

In the StressCheck file provided the 9-7/8 in. drilling liner is termed a production liner. This probably reflects the original intent of the liner, as the design of the well was revised multiple times. In this study the 9-7/8 in. liner will be subjected to drilling (*i.e.*, intermediate) liner loads to determine its fitness for design.

According to Table 3 the drilling (*i.e.*, intermediate) liner is designed to meet the following

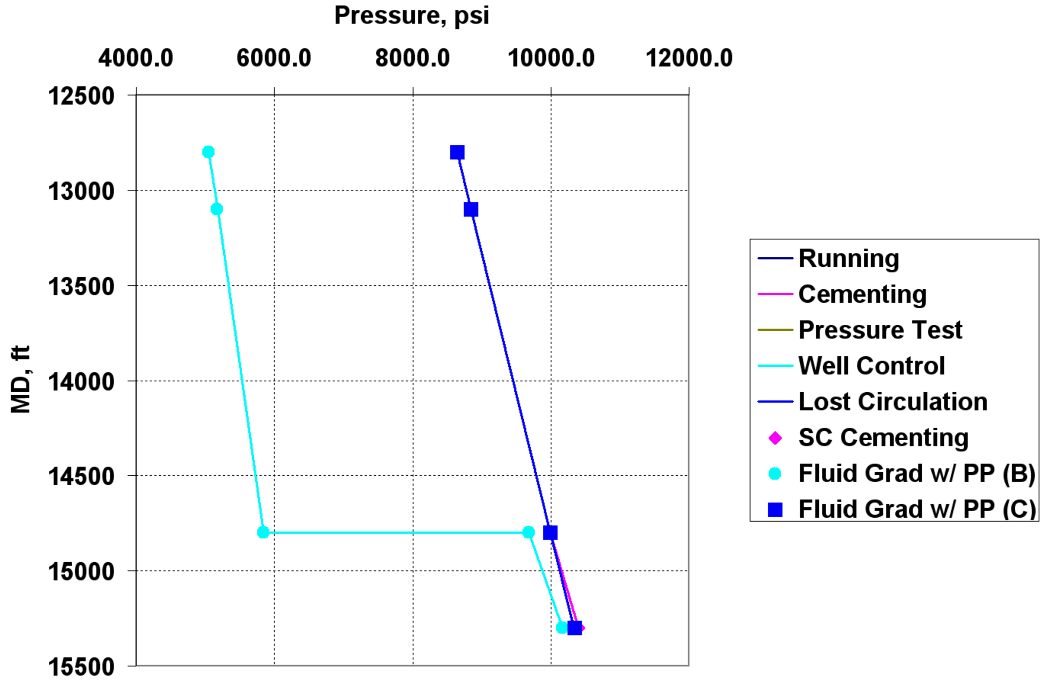

Figure 21. Comparison of Reference [3] and StressCheck External Pressure Loads, 11-7/8 in. Drilling Liner, (B) = Burst, (C) = Collapse

loads:

1. Running casing;
2. Cementing (conventional);
3. Bumping cement plug[38];
4. Pressure test;
5. Well control, possible hydrocarbon;
6. Lost circulation.

Mississippi Canyon 252 No. 1 was designed for all of the above loads using StressCheck. Figures 23 and 24 compare spreadsheet calculated internal and external pressure profiles, respectively, with the same profiles used by StressCheck in its design calculations. In each figure the solid lines represent the spreadsheet calculated pressures, and the symbols reproduce StressCheck pressures

[38]StressCheck terms this load case Green Cement Pressure Test.

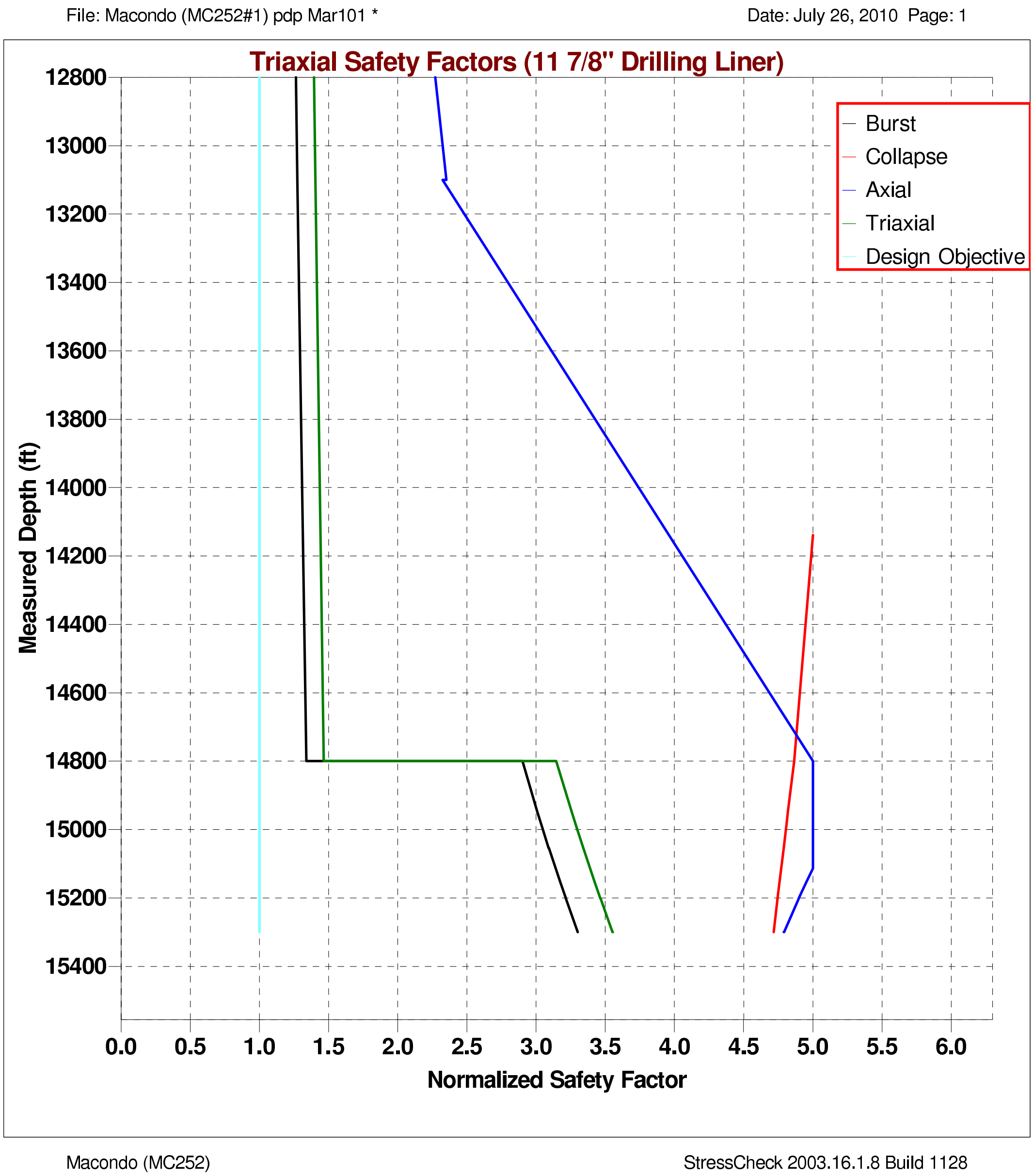

Figure 22. StressCheck Normalized Final Design (Safety) Factors, 11-7/8 in. Drilling Liner

at selected landmarks in the tubular string[39]. StressCheck pressures are determined by linearly interpolating between the landmark values. For both internal and external profiles the StressCheck

[39]The curve used for the Running load case is overlaid by other pressure profiles—internal pressure for the Running load case is identical to the Cementing load case and external pressure for the Running load case is identical to the Lost Circulation load case.

pressures duplicate those calculated with the spreadsheet, with two exceptions.

1. The internal pressure profile for the Pressure Test load case is absent from the design of this string. This appears to be an inadvertent load case omission.

2. There is a slight discrepancy in the well control load due to the use of a simpler model by the spreadsheet. The symbols representing the calculation by StressCheck should be honored, even though they are slightly lower than the spreadsheet values.

Additional points worth noting include the following:

- The discontinuity in the external pressure profile for loads dominated by internal pressure such as the Pressure Test occurs at the previous casing shoe (15,300 ft) where the BP burst back-up switches from a fluid column representing either mud or cement mix fluid to local pore pressure.

The load cases in Table 3 labeled "S" and "CMT" are associated with the undisturbed temperature profile[40], implying no temperature change. Load cases labeled "CT" are associated with a circulating temperature calculated by StressCheck.

Figure 25 is a plot of final design factors as computed by StressCheck for the load cases enumerated above. The abscissa is normalized safety factor in order to view all limit modes on a single plot. All limit modes (internal pressure or "burst", external pressure or collapse, axial yield and triaxial yield) have final design factors above one, indicating an adequate design for the load cases considered. The StressCheck design load line at any depth is the maximum load (for that limit mode) of all cases considered. Over the length of the tubular that maximum can vary from one load case to another. The influence of the previous shoe at 15,300 ft is apparent in the final design factor calculation.

4.11 9-7/8 in. × 7 in. Production Casing

According to Table 4 the production casing is designed to meet the following loads:

1. Running casing;

2. Cementing (conventional);

[40] For this string the Green Cement Pressure Test uses a slightly different temperature profile than undisturbed, but this should have minimal impact on design calculations. The Green Cement Pressure Test models bumping the cement plug and is usually not a governing load case as, in the absence of axial constraint while the cement is unset, the only effect of temperature is adjustment of the tube material yield stress. Similar comments apply to the Cementing load case whose temperature profile also differs slightly from undisturbed.

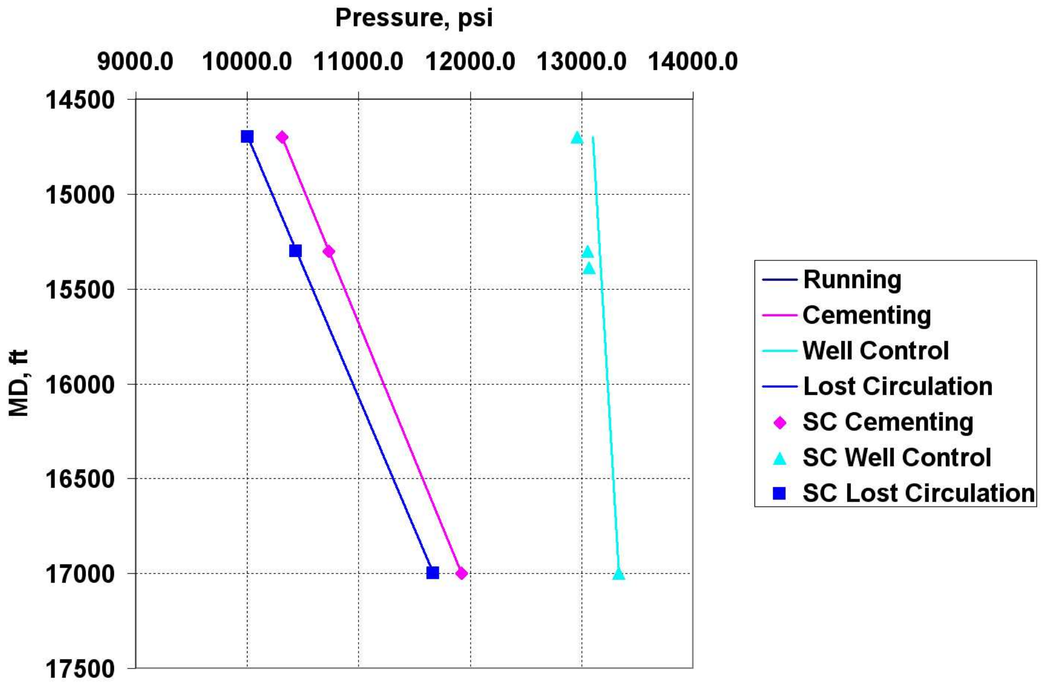

Figure 23. Comparison of Reference [3] and StressCheck Internal Pressure Loads, 9-7/8 in. Drilling Liner

3. Bumping cement plug[41];

4. Pressure test;

5. Tubing leak;

6. Production collapse.

Mississippi Canyon 252 No. 1 was designed for all of the above loads except Cementing using StressCheck. Figures 26 and 27 compare spreadsheet calculated internal and external pressure profiles, respectively, with the same profiles used by StressCheck in its design calculations[42]. In each figure the solid lines represent the spreadsheet calculated pressures, and the symbols reproduce StressCheck pressures at selected landmarks in the tubular string[43]. StressCheck pressures

[41]StressCheck terms this load case Green Cement Pressure Test.

[42]The missing Cementing load case has been added by the author.

[43]The curve used for the Running load case is overlaid by other pressure profiles—internal pressure for the Running load case is identical to the Cementing load case and external pressure for the Running load case is identical to the Lost Circulation load case.

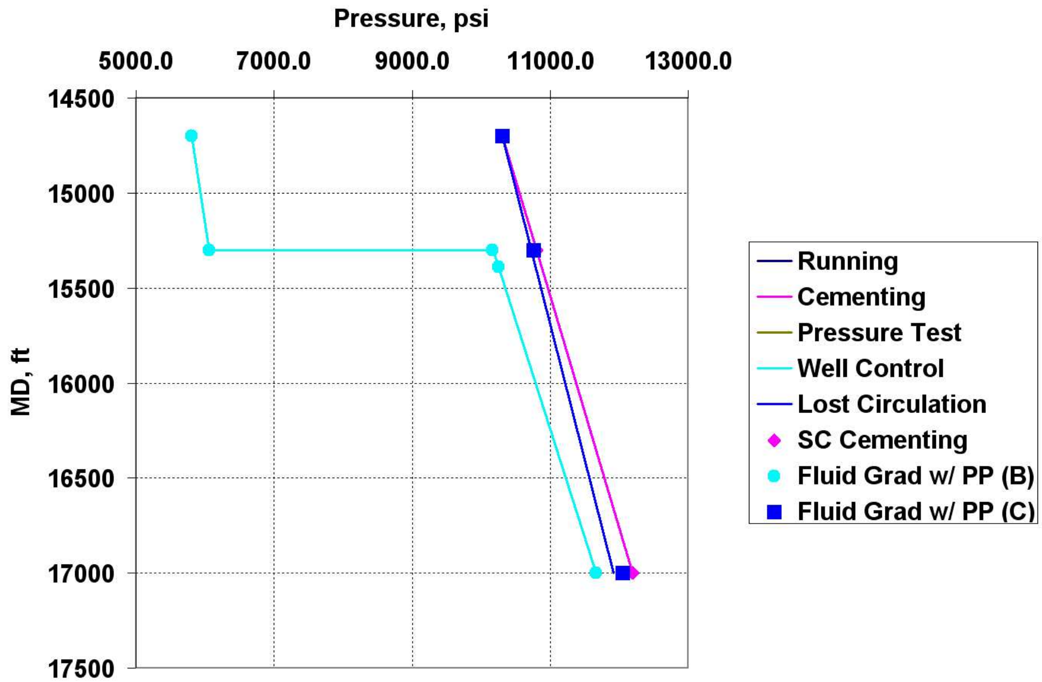

Figure 24. Comparison of Reference [3] and StressCheck External Pressure Loads, 9-7/8 in. Drilling Liner, (B) = Burst, (C) = Collapse

are determined by linearly interpolating between the landmark values. For both internal and external profiles the StressCheck pressures duplicate those calculated with the spreadsheet, with two exceptions.

1. The internal pressure profile for the Pressure Test load case is absent from the design of this string. This appears to be an inadvertent load case omission.

2. There is a slight discrepancy in the tubing leak load due to the use of a simpler model for the gas column to surface by the spreadsheet. The symbols representing the calculation by StressCheck should be honored, even though they are slightly lower than the spreadsheet values.

Additional points worth noting include the following:

- The internal pressure profile below the packer for the Above/Below Packer (Production collapse) load case uses a 5.2 ppg oil gradient. Below the packer the BP *Tubular Design Manual* recommends a density of 0.1 psi/ft, roughly a gas gradient, but allows this gradient to be replaced based on the gas/oil ratio of the anticipated produced fluids. The use of an

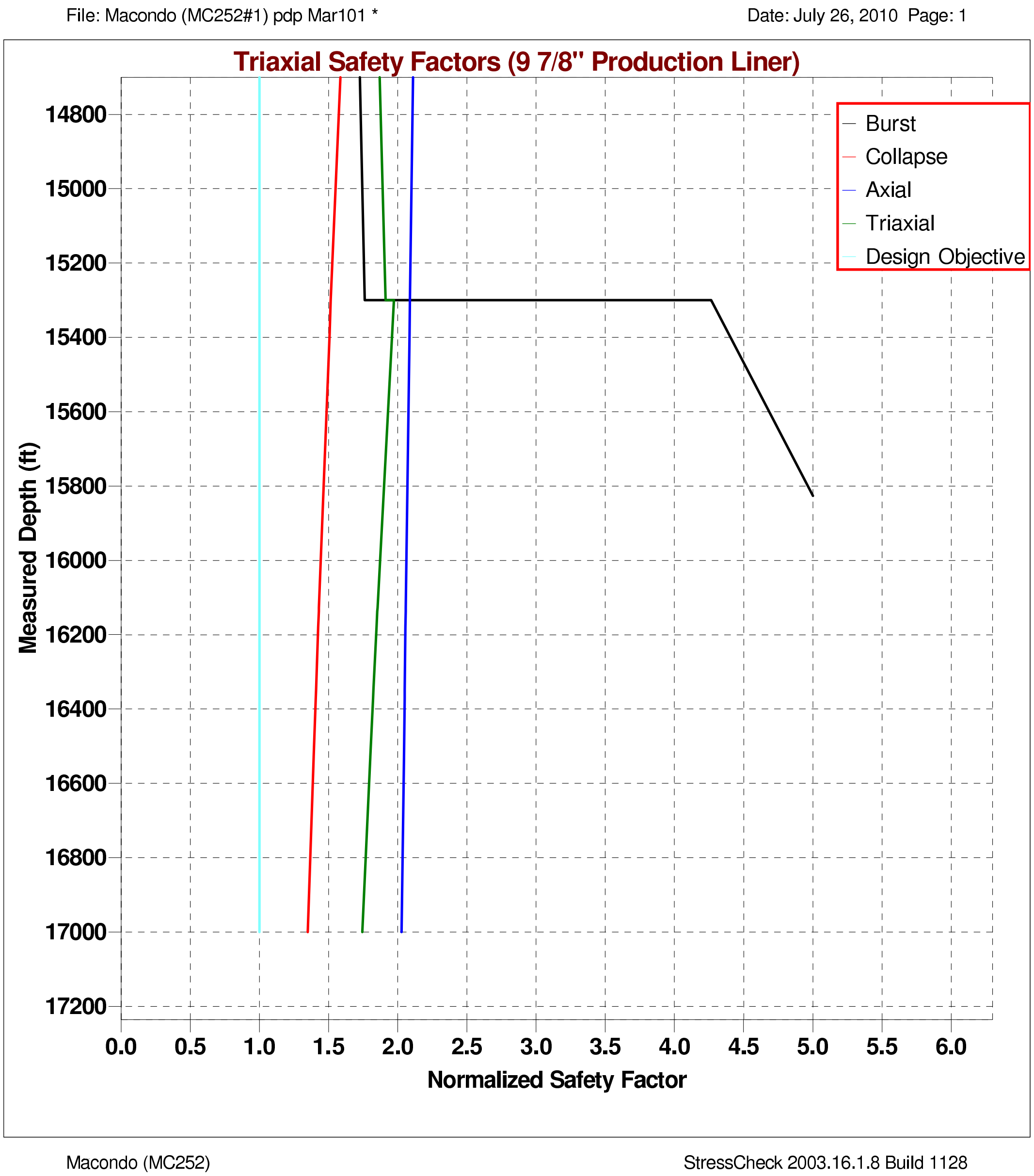

Figure 25. StressCheck Normalized Final Design (Safety) Factors, 9-7/8 in. Drilling Liner

oil gradient is addressed in a deviation request[44]. The abandonment pressure was taken to be 5,150 psi—the pre-drill abandonment pressure for Mississippi Canyon 252 No. 1 was

[44] "9 875 Collapse Dispensation 6-20-2009.docm". The deviation requests an oil gradient of 4.9 ppg, whereas the StressCheck file uses 5.2 ppg.

5,300 psi[45].

A later check of the design using as-built conditions uses an oil gradient of 4.37 ppg. The discrepancy between the original and as-built densities is due to improved pressure-volume-temperature (PVT) data now as compared to the pre-drill design.

- The discontinuity in the external pressure profile for loads dominated by internal pressure such as the Pressure Test occurs at the top-of-cement (17,000 ft) where the BP burst back-up switches from a fluid column representing either mud or cement mix fluid to local pore pressure.

- The discontinuity in the slope of the external pressure profile for Cementing occurs at the top-of-cement (17,000 ft) and is due to a change in external fluid density.

The load cases in Table 4 labeled “S” and “CMT” are associated with the undisturbed temperature profile[46], implying no temperature change. Load cases labeled “P” are associated with a producing temperature calculated by StressCheck.

Figure 28 is a plot of final design factors as computed by StressCheck for the load cases enumerated above. The abscissa is normalized safety factor in order to view all limit modes on a single plot. All limit modes (internal pressure or “burst”, external pressure or collapse, axial yield and triaxial yield) have final design factors above one, indicating an adequate design for the load cases considered. The StressCheck design load line at any depth is the maximum load (for that limit mode) of all cases considered. Over the length of the tubular that maximum can vary from one load case to another. The influences of the change in cross section (14,500 ft) and grade (14,553 ft) in the tubulars, the packer at 11,750 ft and the top-of-cement at 17,000 ft are apparent in the final design factor calculation.

5 Comparison with Industry Practice

Comparing the design of Mississippi Canyon 252 No. 1 to BP design practice raised the question of the severity of BP casing designs with respect to those of other operators. Lack of access to the design manuals of other operators renders such a comparison unlikely. As an alternative, however, comparison can be made to publications in common use by the industry, such as textbooks.

[45] Email from Kelly McAughan dated 26May10.

[46] For this string the Green Cement Pressure Test uses a slightly different temperature profile than undisturbed, but this should have minimal impact on design calculations. The Green Cement Pressure Test models bumping the cement plug and is usually not a governing load case as, in the absence of axial constraint while the cement is unset, the only effect of temperature is adjustment of the tube material yield stress.

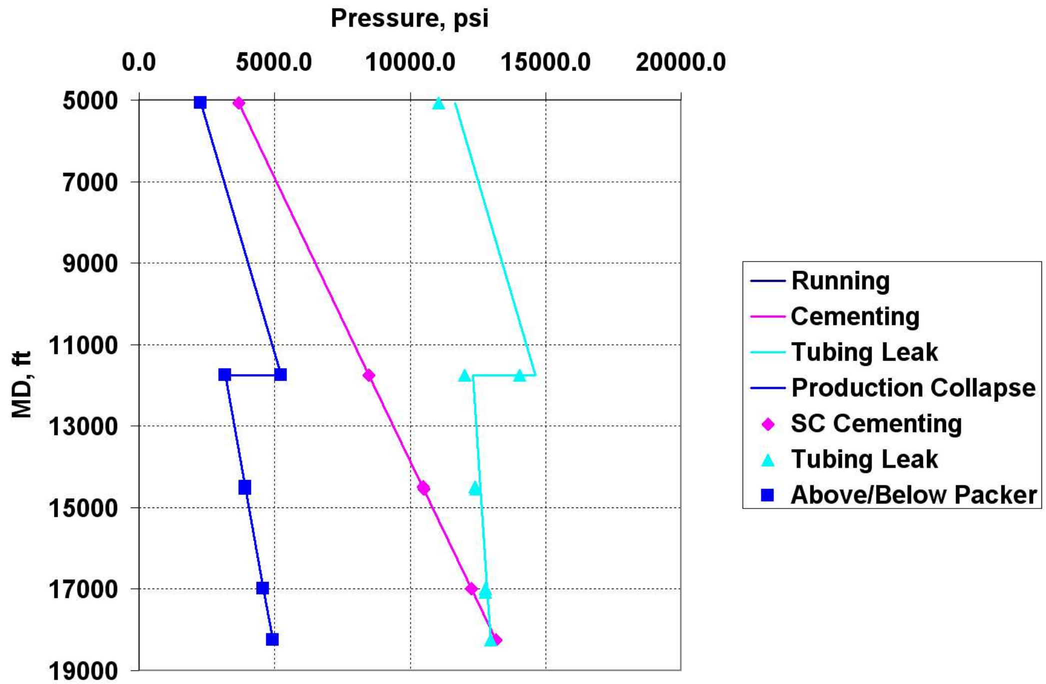

Figure 26. Comparison of Reference [3] and StressCheck Internal Pressure Loads, 9-7/8 in. × 7 in. Production Casing

5.1 Advanced Drilling and Well Technology, Society of Petroleum Engineers [7]

The newly released SPE textbook represents the most recent source for common industry casing design practice. Table 8 is taken directly from the reference and lists recommended loads for drilling (*i.e.*, intermediate) casing and liners. The recommendations in this table should be compared to those of Table 3.

The footnotes in Table 8 provide a quick comparison between the BP design parameters and [7]. In addition, the following detailed comments are pertinent:

- The MASP in BP design practice for the Kick load condition starts with fracture pressure at the casing shoe minus a gas gradient to surface. If liners are run below the tubular string being designed, the fracture pressure will be evaluated at the deepest exposed shoe.

- The back-up pressure in BP design practice for Burst load conditions is slightly more conservative than [7]. Use of mix fluid density is continued in open hole down to the top-of-cement. Local pore pressure is used in open hole below the top-of-cement.

- Of the options recommended by the SPE textbook for Kick load condition temperature, BP

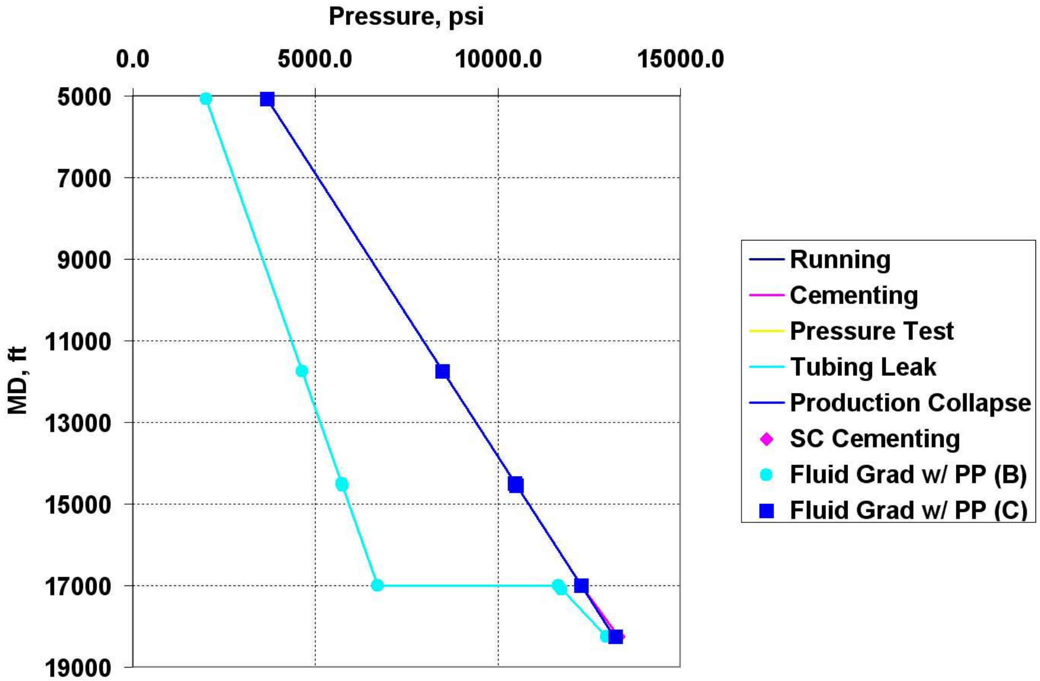

Figure 27. Comparison of Reference [3] and StressCheck External Pressure Loads, 9-7/8 in. × 7 in. Production Casing, (B) = Burst, (C) = Collapse

Table 8. Drilling Loads for Drilling Casings and Liners

Load Type	Load Condition	Internal Pressure	External Pressure	Temperature Profile
Burst	Kick	MASP on a gas or fluid gradient[a]	Mud or base fluid gradient above previous shoe, pore pressure in open hole[d]	Circulating[a] or geothermal
Burst	Pressure test	Test pressure on the internal fluid gradient[a]	Mud or base fluid gradient above previous shoe, pore pressure in open hole[d]	Geothermal[a]
Collapse	Drilling collapse	Zero to top of fluid, internal fluid gradient to shoe[b]	Mud gradient[a] or mud and cement gradient[c]	Geothermal[a]
Collapse	Cement collapse	Displacement fluid gradient[a]	Mud and cement gradient to casing shoe[a]	Geothermal[e]
Tension	Bump plug	Displacement pressure plus bump plug margin above fluid gradient[a]	Mud and cement gradient to casing shoe[a]	Geothermal[a]
Tension	Running overpull	Mud gradient[a]	Mud gradient to casing shoe[a]	Geothermal[a]

MASP–maximum anticipated surface pressure

[a] Identical to BP design load.

[b] Identical to one of the BP design load options.

[c] More severe than the BP design load.

[d] Less severe than the BP design load.

[e] Difficult to determine without thermal modeling of particular well conditions.

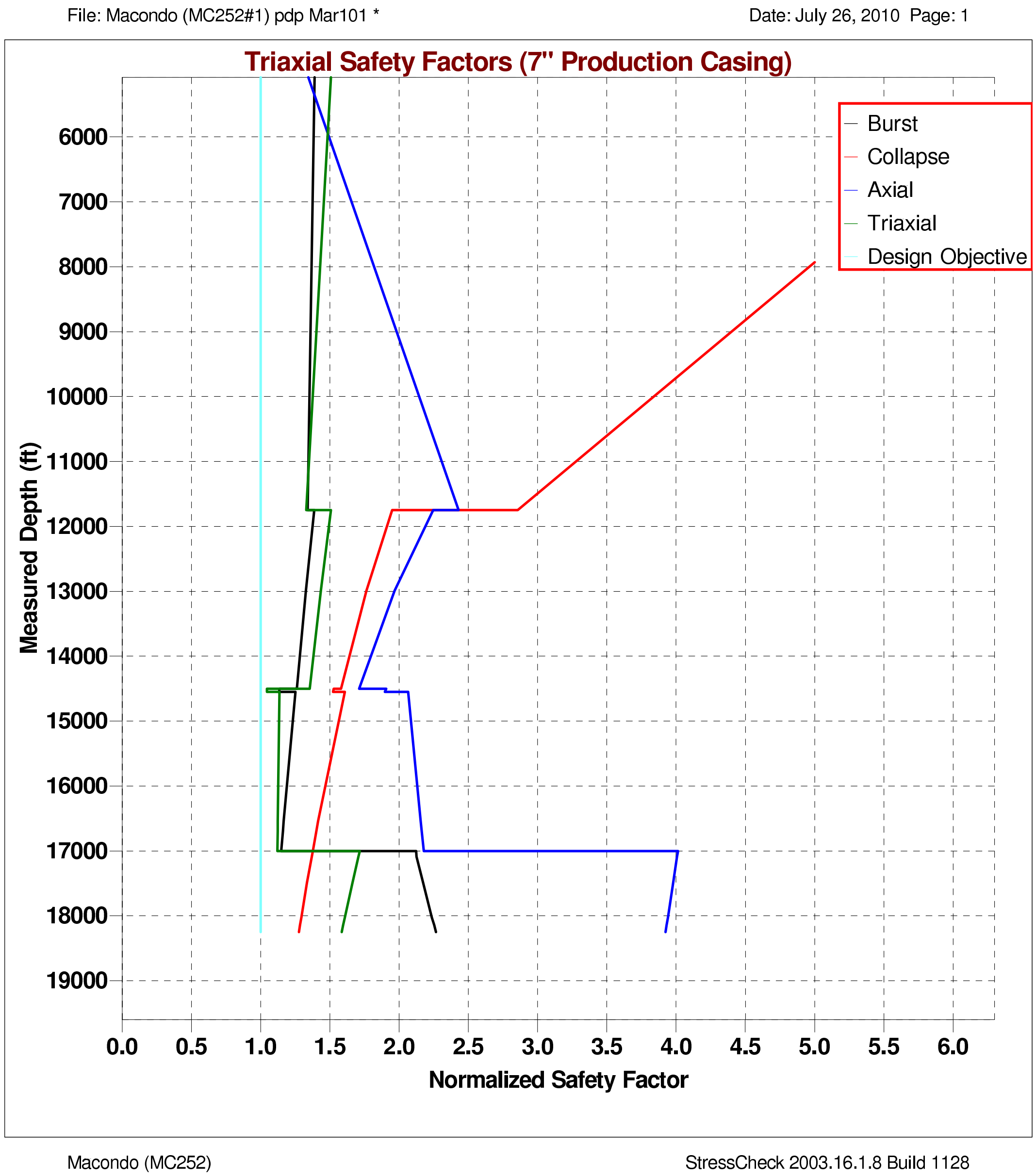

Figure 28. StressCheck Normalized Final Design (Safety) Factors, 9-7/8 in. × 7 in. Production Casing

uses the circulating temperature.

- Although the BP *Tubular Design Manual* permits a salt water gradient for the Drilling Collapse (*i.e.*, lost circulation) load condition, Mississippi Canyon 252 No. 1 was designed with the more onerous case of evacuation to a mud column that balances open hole pore pressure.

Table 9. Production Loads for Production Casings and Liners

Load Type	Load Condition	Internal Pressure	External Pressure	Temperature Profile
Burst	Tubing leak	SITP on packer fluid gradient[a]	Base fluid gradient above previous shoe, pore pressure below[d]	Producing[a] and geothermal
Burst	Pressure test or simulation down casing	Surface pressure on internal fluid gradient[a]	Base fluid gradient above previous shoe, pore pressure below[d]	Geothermal for test pressure[a], Stimulation for stimulation load[a]
Burst	Stimulation through tubing	Surface pressure above packer fluid gradient[a]	Base fluid gradient above previous shoe, pore pressure below[d]	Stimulation[a]
Collapse	Cement collapse	Displacement fluid gradient[a]	Mud and cement gradient to casing shoe[a]	Geothermal[e]
Collapse	Production collapse	Zero pressure or packer fluid balancing abandonment pressure[b]	Mud gradient[a] or mud and cement gradient[c]	Geothermal[a]
Tension	Bump plug	Displacement pressure plus bump plug margin above displacement fluid gradient[a]	Mud and cement gradient to casing shoe[a]	Geothermal[a]
Tension	Running overpull	Mud gradient[a]	Mud gradient to casing shoe[a]	Geothermal[a]

MASP–maximum anticipated surface pressure

[a] Identical to BP design load.

[b] Identical to one of the BP design load options.

[c] More severe than the BP design load.

[d] Less severe than the BP design load.

[e] Difficult to determine without thermal modeling of particular well conditions.

- BP uses a mud gradient behind casing for all collapse load conditions except the act of cementing itself.
- In some instances BP uses the cementing temperature instead of geothermal temperature for the Bump Plug load condition. This has a minor effect on the design, as no thermal loads are generated prior to cement solidification.
- The default overpull in BP design practice for the Running Overpull load condition is 100,000 lbs (see BP *Tubular Design Manual*).

The above discussion indicates that BP's design of surface and intermediate casing and liners aligns with standard industry practice, deviations being of a nature that are either open to designer preference or not crucial to tubular integrity.

Table 9 is taken directly from the reference and lists recommended loads for production casing and liners. The recommendations in this table should be compared to those of Table 4.

The footnotes in Table 9 provide a quick comparison between the BP design parameters and [7]. In addition, the following detailed comments are pertinent:

- The Stimulation Through Tubing load condition is not applicable to this design.
- The back-up pressure in BP design practice for Burst load conditions is slightly more conservative than [7]. Use of mix fluid density is continued in open hole down to the top-of-cement.

Table 10. Typical Design Factors

Minimum Safety Factors[a]—Casing	Pipe Body
VME[b]	1.25
Axial	1.3–1.6
Burst (MIYP)	1.0–1.25
Collapse	1.0–1.1

[a]SPE's "safety factor" is tantamount to BP's "design factor".

[b]VME or "von Mises equivalent" refers to the triaxial stress state.

Local pore pressure is used in open hole below the top-of-cement.

- BP uses a mud gradient behind casing for all collapse load conditions except the act of cementing itself.
- In some instances BP uses the cementing temperature instead of geothermal temperature for the Bump Plug load condition. This has a minor effect on the design, as no thermal loads are generated prior to cement solidification.
- The default overpull in BP design practice for the Running Overpull load condition is 100,000 lbs (see BP *Tubular Design Manual*).

The above discussion indicates that BP's design of production casing and liners aligns with standard industry practice, deviations being of a nature that are either open to designer preference or not crucial to tubular integrity.

The requirement that tubular resistance be greater than the maximum anticipated load is usually modified by a design factor to accommodate uncertainties in the estimation of resistance, load or both. Table 10 is taken directly from the reference and lists typical ranges of design factor for various resistance/load comparisons. The recommendations in this table should be compared to those of Table 5. Comparing the two tables, BP's design factors fall within the ranges used elsewhere in the industry.

5.2 Modern Well Design, Bernt S. Aadnœy [1]

The well design load cases in [1] are similar to those discussed above in [7]. For drilling casing the well control load is of a limited kick nature (*e.g.*, less severe than the BP starting point of fracture

Table 11. Drilling Loads for Drilling Casings and Liners

Load Type	Load Condition	Internal Pressure	External Pressure	Temperature Profile
Burst	Kick	MASP^{a,d}	Seawater^{e}	Not found in reference
Collapse	Drilling collapse	Zero to top of fluid, internal fluid gradient to shoe^{c}	Mud gradient^{a} or seawater, mud and wet cement gradient^{e}	Not found in reference
Tension	Running overpull, running resistance	Mud gradient^{a}	Mud gradient to casing shoe^{a}	Not found in reference

MASP–maximum anticipated surface pressure

^{a}Identical to BP design load.

^{b}Identical to one of the BP design load options.

^{c}More severe than the BP design load.

^{d}Less severe than the BP design load.

^{e}Difficult to determine without knowledge of particular well conditions.

at shoe, gas to surface). For production casing, a shallow tubing leak similar to that used by [7] is proposed[47].

Collapse load cases modeling both lost circulation and cementing are recommended to cover most of the collapse scenarios discussed in the text. The former is somewhat more conservative than either BP or [7] in that the mud for the next hole section is balanced with a seawater gradient rather than local pore pressure.

Table 11 is taken directly from the reference and lists recommended loads for drilling (*i.e.*, intermediate) casing and liners in exploratory wells. The recommendations in this table should be compared to those of Table 3.

The footnotes in Table 11 provide a quick comparison between the BP design parameters and [1]. In addition, the following detailed comments are pertinent:

- BP's MASP for the Kick load condition starts with fracture pressure at the casing shoe minus a gas gradient to surface. If liners are run below the tubular string being designed, the fracture pressure will be evaluated at the deepest exposed shoe. Reference [1] uses a different MASP for surface and intermediate casing, with the surface casing MASP being close to that used by BP, whereas the MASP for intermediate casing is calculated using formation pressure from the next hole section.

- BP's back-up pressure for Burst load conditions is slightly more conservative than [1] down to the top-of cement in open hole. BP uses local pore pressure in open hole below the top-of-cement, which is usually less onerous than the seawater gradient used by [1].

[47] Aadnœy also proposes a gas filled load case for production casing. This scenario is less onerous than the shallow tubing leak that BP models, as the BP shallow tubing leak load case uses a gas gradient to compute the surface annulus pressure, but then places that on top of a completion fluid gradient.

Table 12. Production Loads for Production Casings and Liners

Load Type	Load Condition	Internal Pressure	External Pressure	Temperature Profile
Burst	Tubing leak	Leak in test string or gas filled casing[a]	Seawater[e]	Not found in reference
Collapse	Lost circulation or production	Lost circulation[a] or well flow[d]	Mud gradient[a] or cushion fluid	Not found in reference
Tension	Running overpull, running resistance	Mud gradient[a]	Mud gradient to casing shoe[a]	Not found in reference

MASP–maximum anticipated surface pressure

[a] Identical to BP design load.

[b] Identical to one of the BP design load options.

[c] More severe than the BP design load.

[d] Less severe than the BP design load.

[e] Difficult to determine without knowledge of particular well conditions.

- Reference [1] does not include temperature in its formal, tabular load summary. Elsewhere the author mentions both annular pressure build-up and the effect of temperature on yield strength (both of which are considered by BP). A discussion of selecting temperature profiles to generate thermal loads from some initial temperature profile, however, could not be found.
- The top of fluid for the Drilling Collapse (lost circulation) load condition is determined by assuming the pore pressure gradient is everywhere seawater in [1]. BP uses the local pore pressure, be it above or below a seawater gradient.
- Although the BP *Tubular Design Manual* permits a salt water gradient for the Drilling Collapse (*i.e.*, lost circulation) load condition, Mississippi Canyon 252 No. 1 was designed with the more onerous case of evacuation to a mud column that balances open hole pore pressure.
- BP uses a mud gradient behind casing for all collapse load conditions except the act of cementing itself. It is unclear whether the BP external fluid column (mud) or the reference external fluid column (seawater, mud and wet cement) is more conservative.
- The default overpull in BP design practice for the Running Overpull load condition is 100,000 lbs (see BP *Tubular Design Manual*). Although [1] does not mention overpull, the reference does consider drag, which for BP is a separate calculation outside the conventional casing design.

The above discussion again indicates that BP's design of surface and intermediate casing and liners aligns with standard industry practice.

Table 12 is taken directly from the reference and lists recommended loads for production casing and liners. The recommendations in this table should be compared to those of Table 4.

Table 13. Typical Design Factors

Minimum Safety Factors—Casing	Pipe Body
VME[a]	Not found in reference
Axial	1.1
Burst (MIYP)	1.18
Collapse	1.1

[a]VME or "von Mises equivalent" refers to the triaxial stress state.

The footnotes in Table 12 provide a quick comparison between the BP design parameters and [7]. In addition, the following detailed comments are pertinent:

- BP's back-up pressure for Burst load conditions is slightly more conservative than [1] down to the top-of cement in open hole. BP uses local pore pressure in open hole below the top-of-cement, which is usually less onerous than the seawater gradient used by [1].
- It is unclear whether BP's collapse load case, which drops the completion fluid column to balance abandonment pressure, is more conservative than [1] which uses a seawater gradient as the pore pressure to be balanced by the completion fluid following a packer leak. Below the packer BP is more conservative, recommending a gas gradient or full evacuation.
- The default overpull in BP design practice for the Running Overpull load condition is 100,000 lbs (see BP *Tubular Design Manual*). Although [1] does not mention overpull, the reference does consider drag, which for BP is a separate calculation outside the conventional casing design.

The above discussion again indicates that BP's design of production casing and liners aligns with standard industry practice.

The author could not find a succinct table of design factors in [1]. Table 13 is taken from an example problem in the text and appears to set the range of design factors [1] would consider acceptable. The recommendations in this table should be compared to those of Table 5. Comparing the two tables, BP's design factors approximate those used in [1].

6 Evaluation in As-Built Condition

As a further check of the integrity of the Mississippi Canyon 252 No. 1 well design, an investigation was made with StressCheck of the as-built condition of the well using BP standard loads[48]. An entirely new StressCheck file was constructed, beginning with the BP template. Input data was taken from an up-to-date WellCat file created by Richard A. Miller[49]. Initiation of the file employs the BP StressCheck template BP2007V0.

For each tubular string final design factors for the BP design load cases summarized in Tables 2 through 4 are calculated. Results are presented in Figures 29–37. Viewing the figures the following points are worth noting:

- Figure 31—As was the case with the original design discussed above, the 22 in. casing will not meet the loads associated with Fracture @Shoe w/ Gas Gradient Above, but will meet the loads associated with Gas Kick Profile with BP input parameters. Results using the Gas Kick Profile load case are shown in the plot.

- Figure 33—As was the case with the original design discussed above, the 16 in. casing will meet neither the loads associated with Fracture @Shoe w/ Gas Gradient Above nor Gas Kick Profile. The shortfall for the latter case is, however, not large (1.04 vs. required 1.10 for final Burst design factor, 1.23 vs. 1.25 for final Triaxial design factor, values that are close to the 1.06 and 1.32 Burst and Triaxial final design factors realized in the original design).

- Figure 37—The Above/Below Packer collapse load case for the production casing differs from the original design due to improved reservoir pressure and fluid information. The pre-drill abandonment reservoir pressure was approximately 5,300 psi. Running the same case with updated PVT behavior (due to a higher GOR) the reservoir pressure would be 3,550 psi at abandonment[50]. Figure 37 illustrates the collapse design factor assuming an abandonment pressure of 3,550 psi and a minimum internal fluid density of 4.37 ppg corresponding to the current oil gradient. For the revised abandonment pressure and fluid density the design remains acceptable in collapse.

- Figure 37—Inasmuch as Mississippi Canyon 252 No. 1 was not completed, selection of a packer fluid density had not yet been performed. The as-built Tubing Leak (Burst) load case was

[48] For an investigation of the integrity of the production casing and production casing annulus subjected to loads associated with the *Deepwater Horizon* event, see, respectively, Rich Miller, Technical Note “Macondo: Integrity of the 9-7/8″ × 7″ Production Casing”, Revision A, May 10, 2010, and Rich Miller, Technical Note “Macondo 16″ × 9-7/8″ Annulus Pressure Integrity”, Revision B, May 17, 2010.

[49] “Prod Csg match slides.wcd” dated May 13, 2010.

[50] Email from Kelly McAughan dated 26May10.

constructed from a calculation performed specifically for this investigation[51]. An acceptable range of packer fluid densities from 10.4–11.3 ppg has been determined using normal BP procedures, with the higher value of that range used in this check[52].

References

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[3] BP. *BPA-D-003 Tubular Design Manual*, 2008.

[4] BP. *Casing and Tubing Design Group Practice*, 2008. GP 10-01.

[5] BP. *Drilling and Well Operations Practice*, 2008. GP 10-00.

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[51] Rich Miller, Technical Note "Macondo Completion Allowable Packer Fluid Density," Revision A, July 9, 2010.

[52] In actuality, the lighter end of the acceptable density range would more likely be the final choice, depending on the collapse loading on tubing accessories and differential packer loading, issues outside the scope of this work.

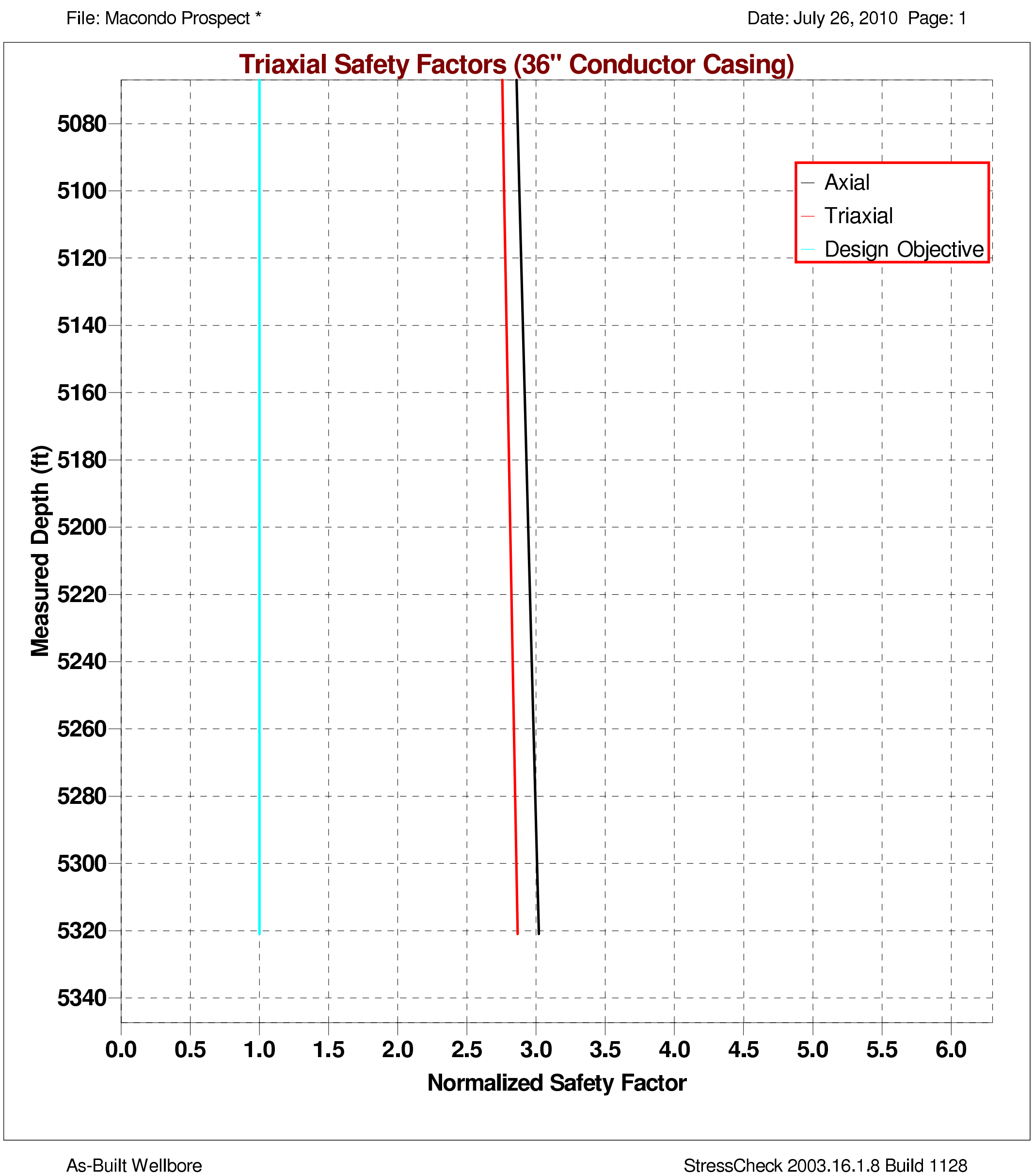

Figure 29. As-Built Normalized Final Design (Safety) Factors, 36 in. Conductor

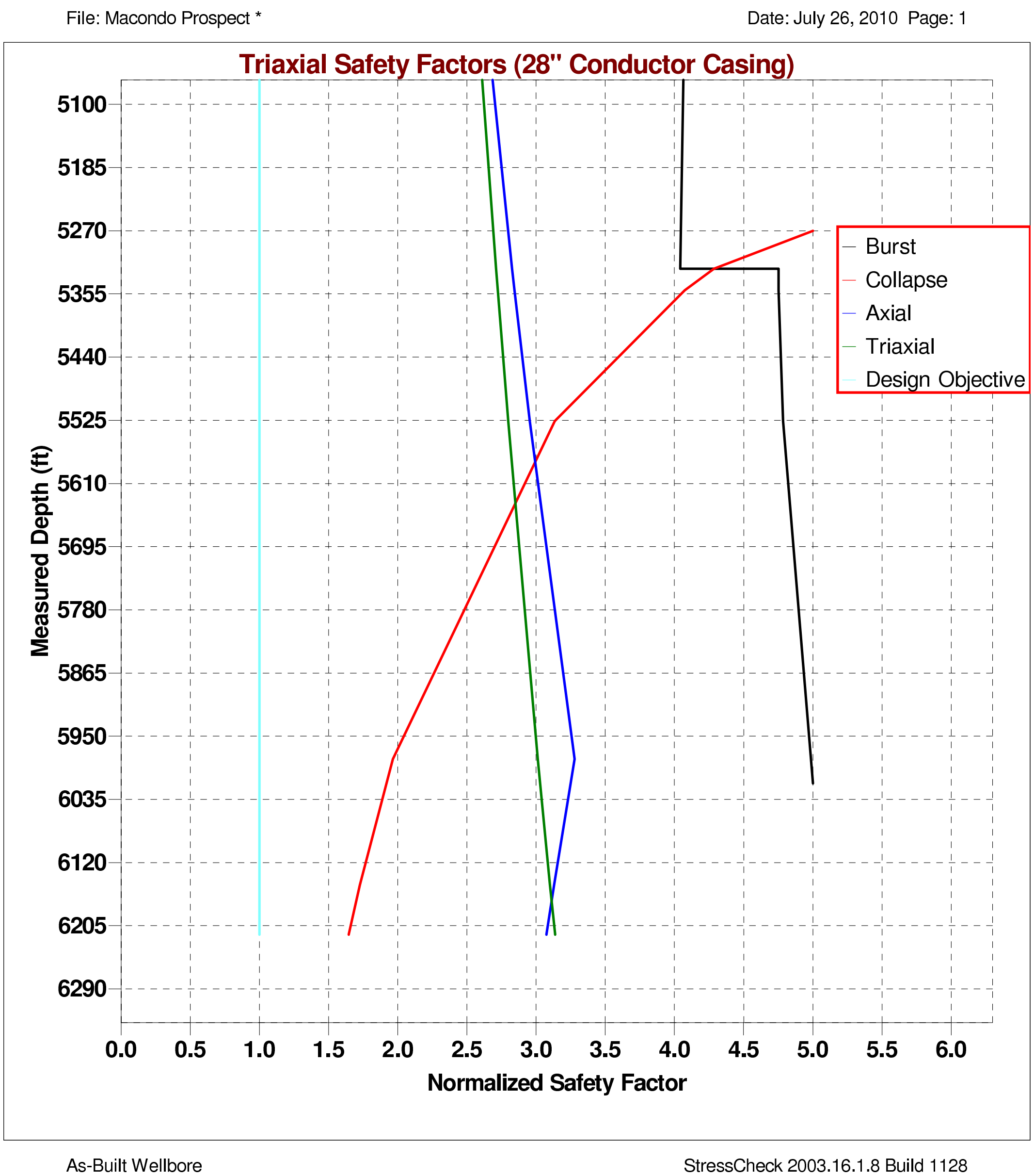

Figure 30. As-Built Normalized Final Design (Safety) Factors, 28 in. Conductor

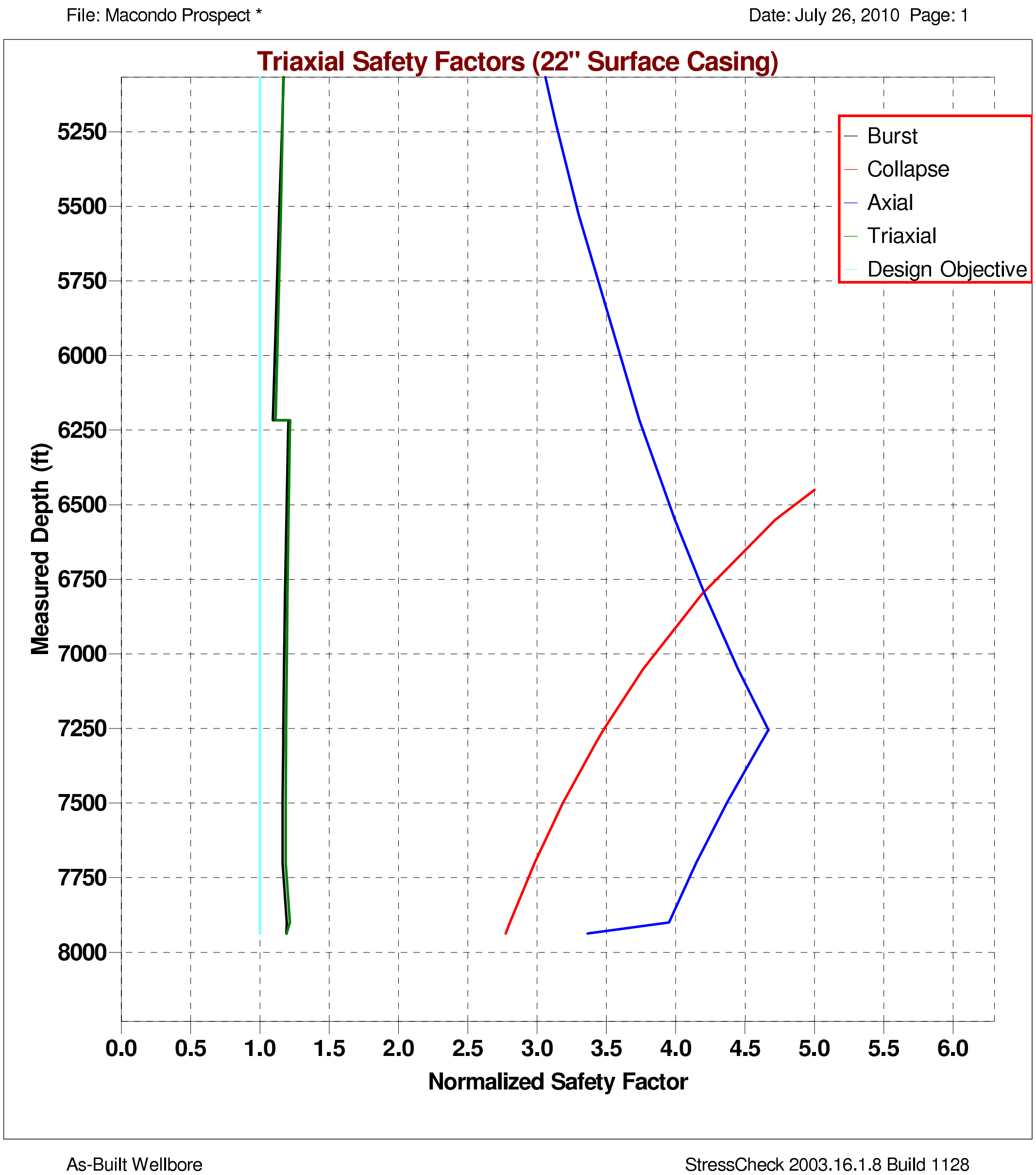

Figure 31. As-Built Normalized Final Design (Safety) Factors, 22 in. Surface Casing

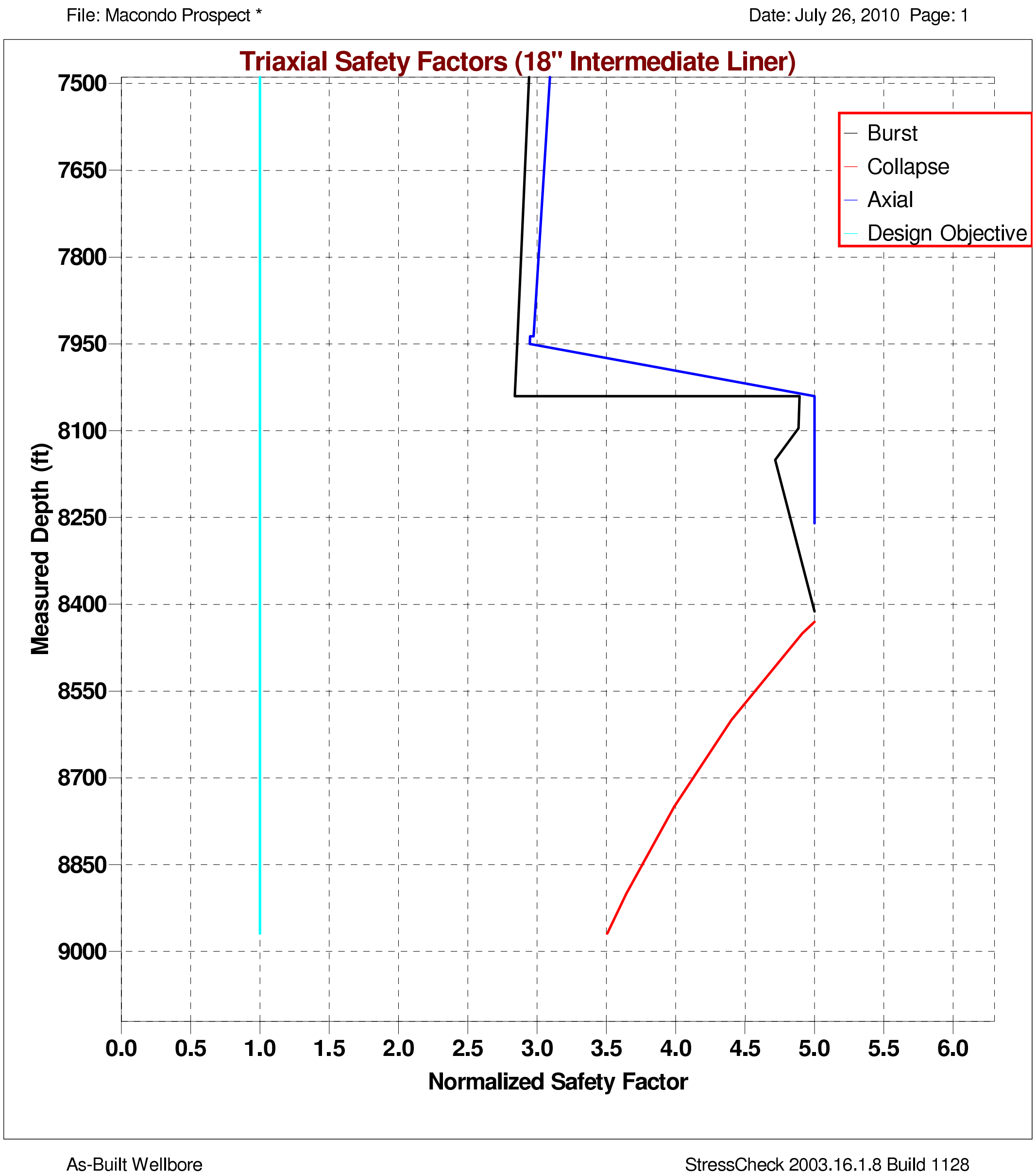

Figure 32. As-Built Normalized Final Design (Safety) Factors, 18 in. Intermediate Liner

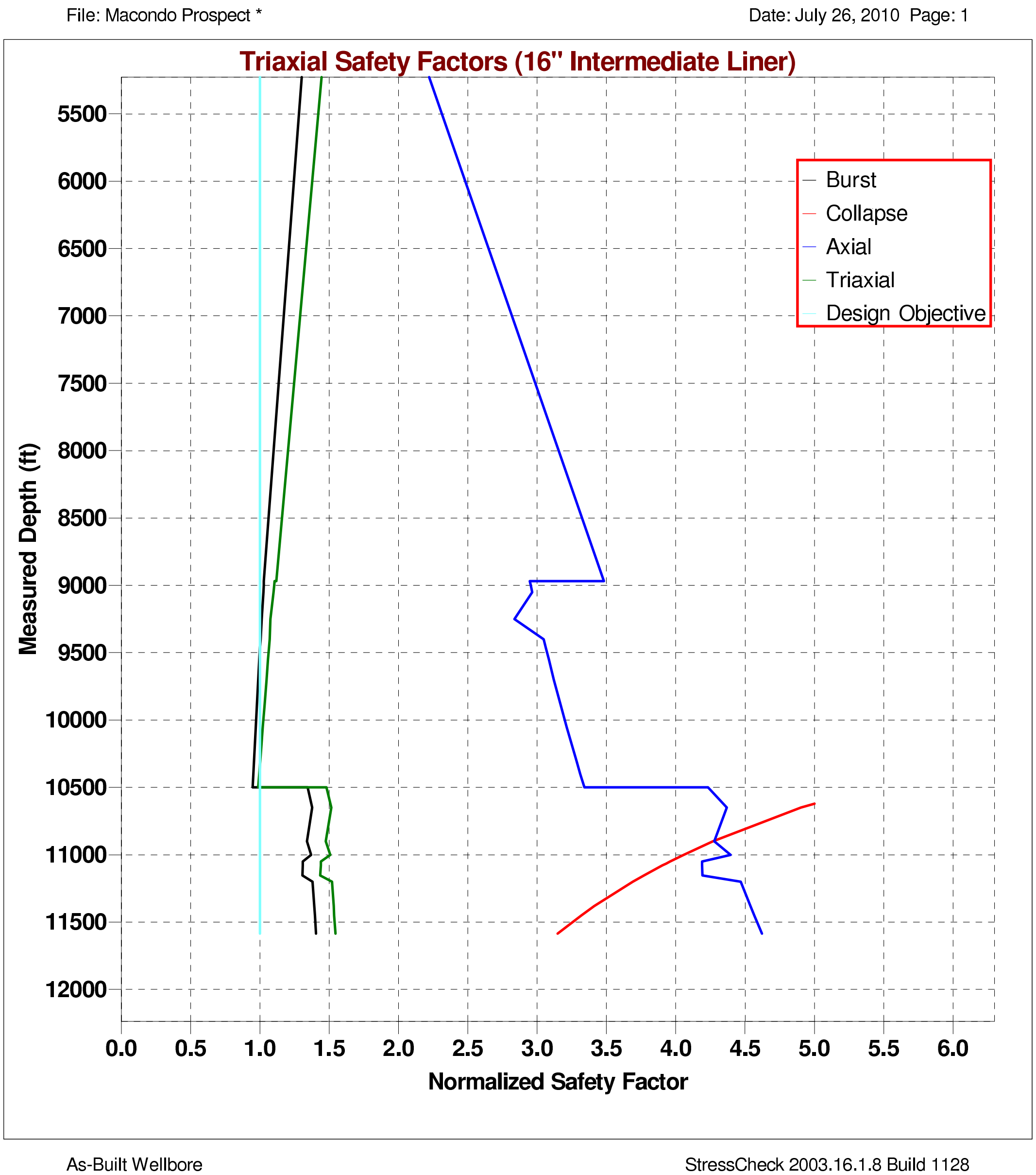

Figure 33. As-Built Normalized Final Design (Safety) Factors, 16 in. Intermediate Casing

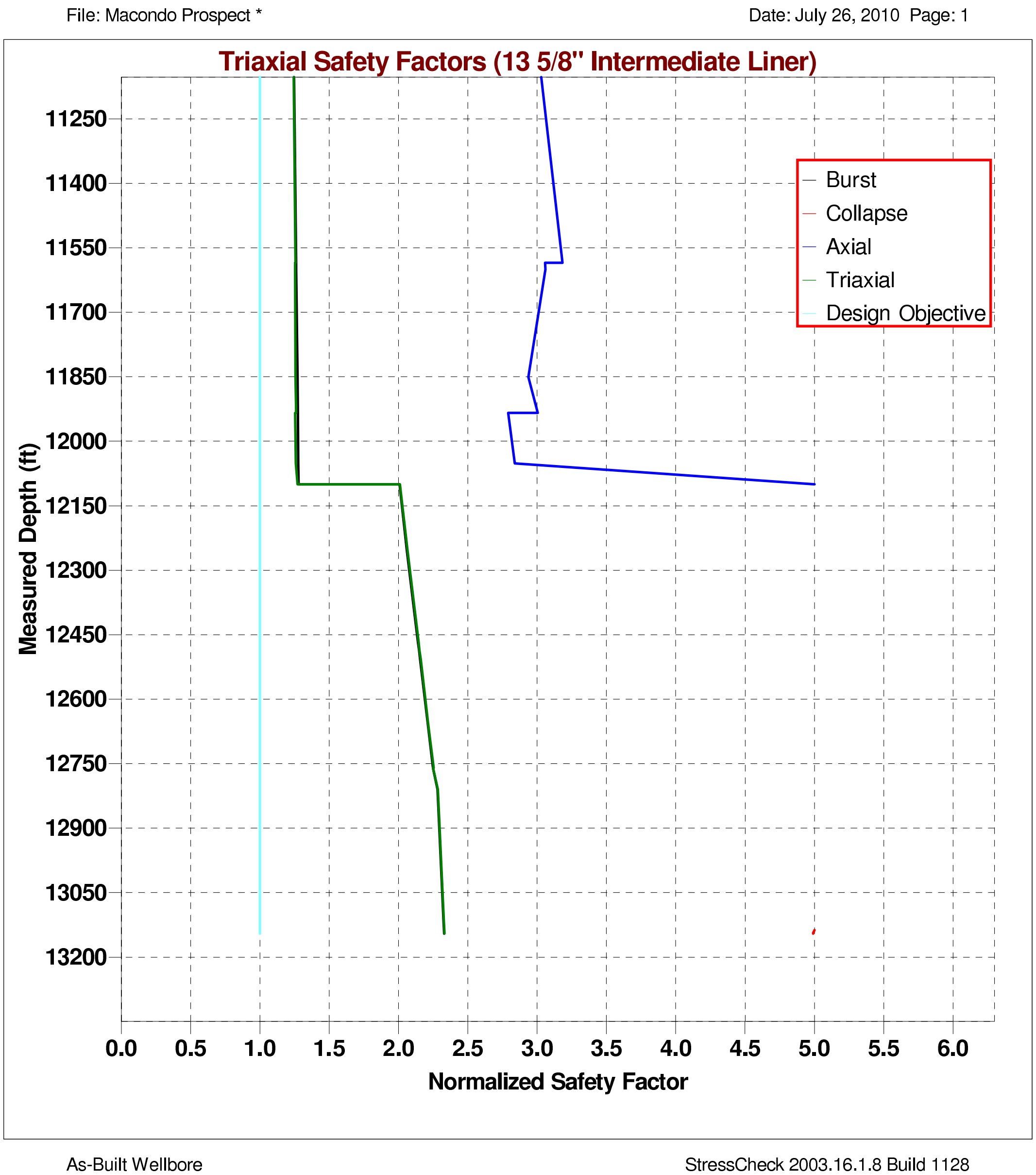

Figure 34. As-Built Normalized Final Design (Safety) Factors, 13-5/8 in. Intermediate Liner

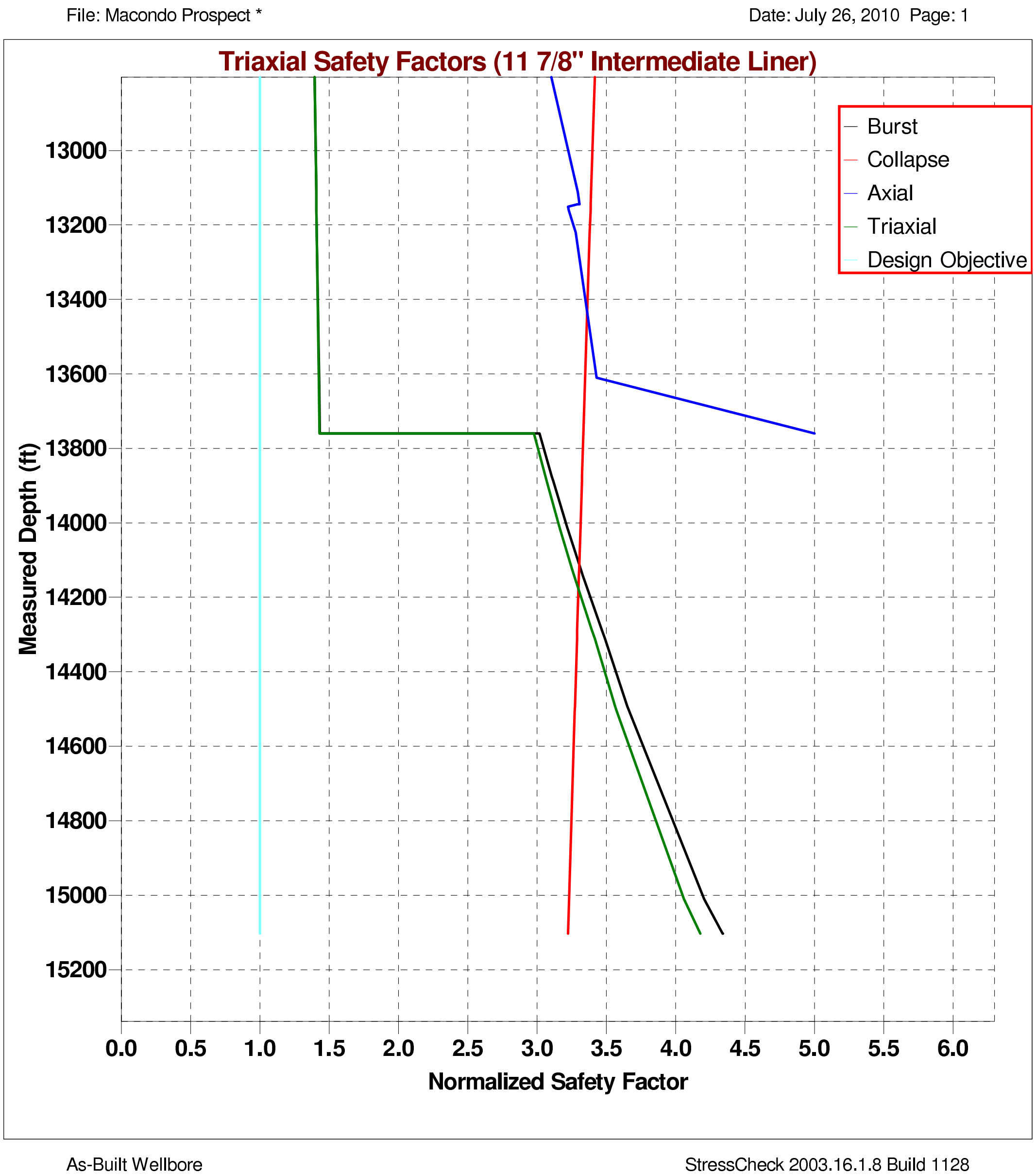

Figure 35. As-Built Normalized Final Design (Safety) Factors, 11-7/8 in. Intermediate Liner

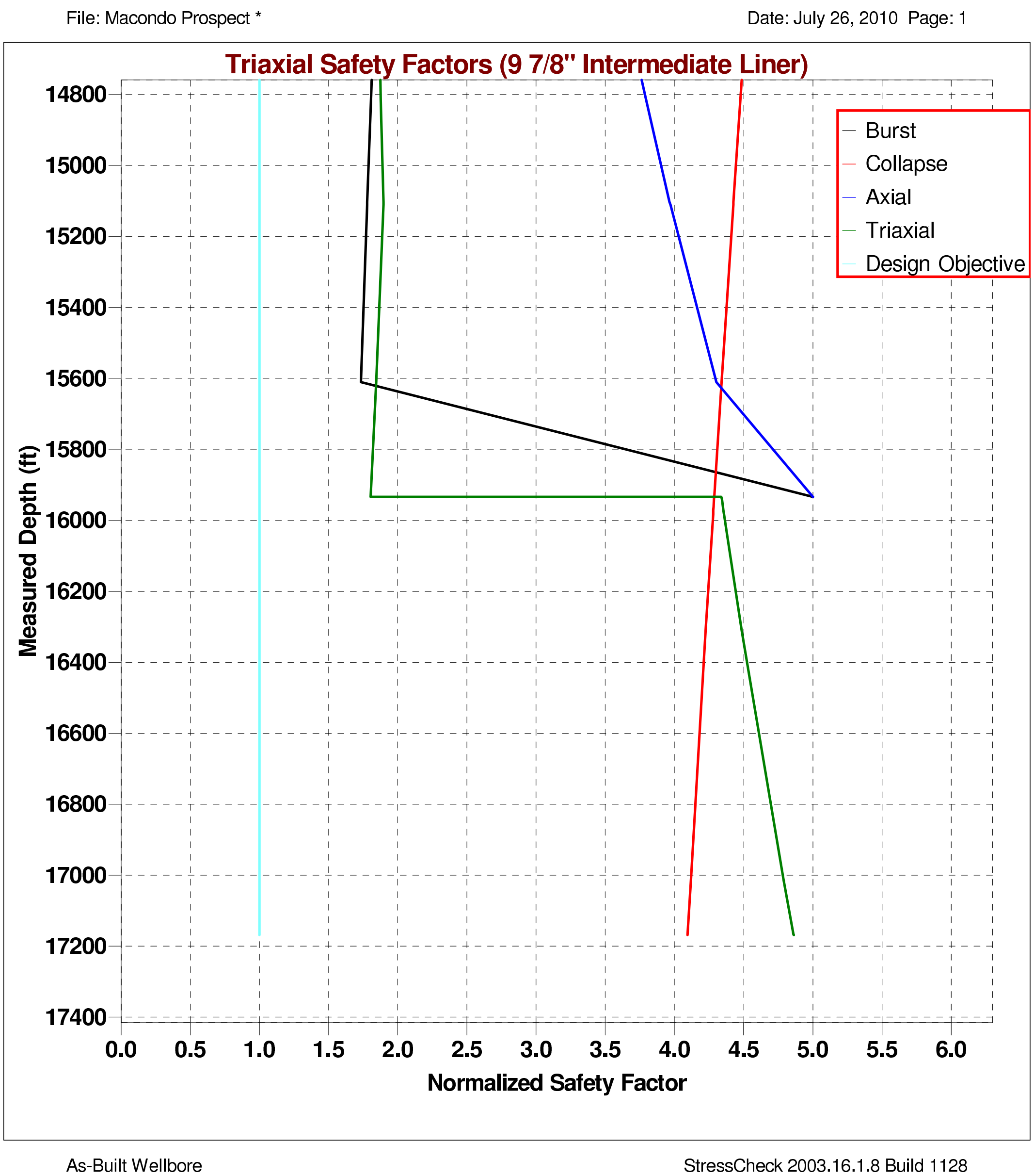

Figure 36. As-Built Normalized Final Design (Safety) Factors, 9-7/8 in. Intermediate Liner

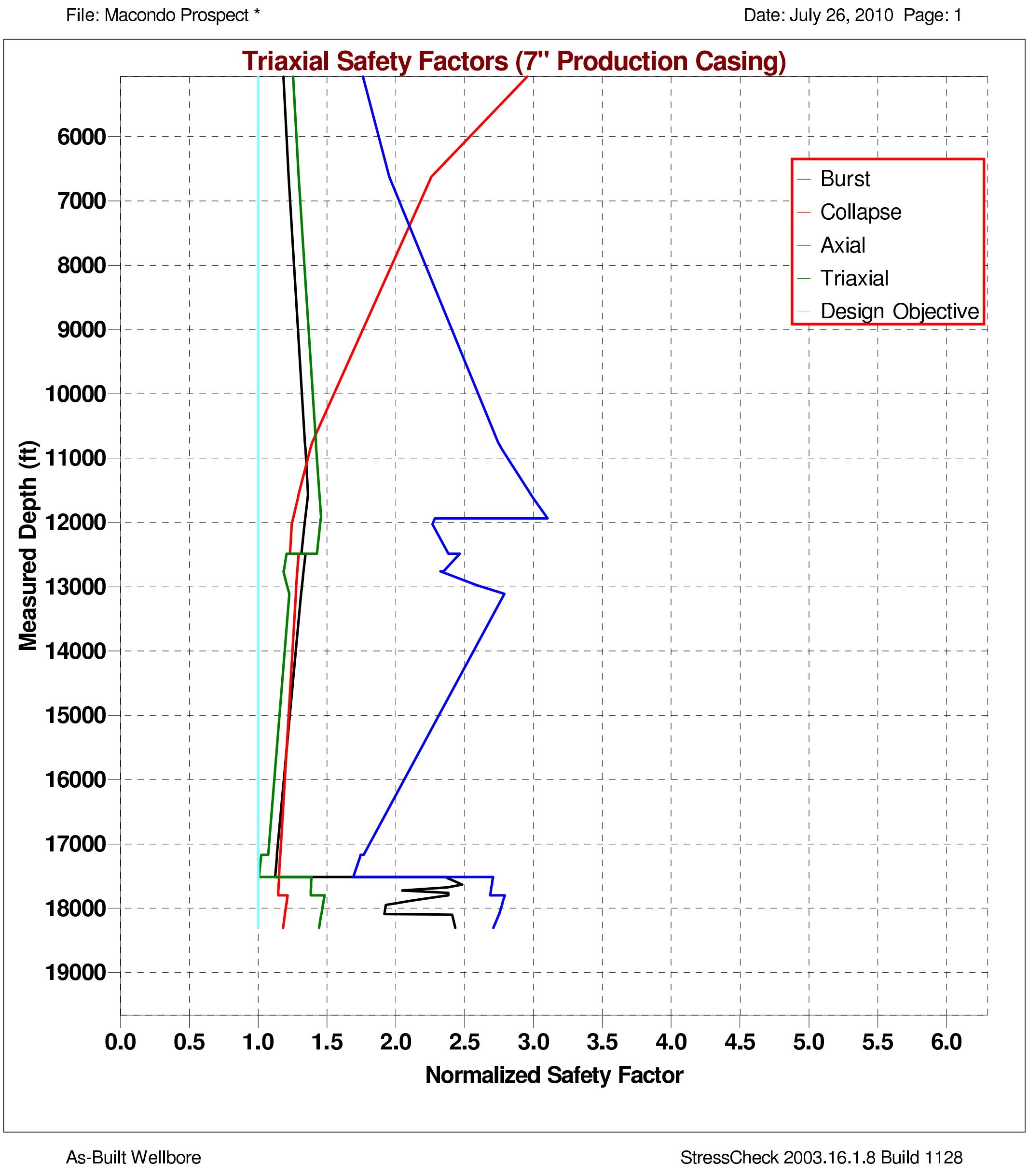

Figure 37. As-Built Normalized Final Design (Safety) Factors, 9-7/8 in. × 7 in. Production Casing